BEFORE
THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA

In the Matter of: Application of Dominion Energy South Carolina, Incorporated for Adjustments of Rates and Charges (See Commission Order No. 2020-313)	))))))	Docket No. 2020-125-E

DIRECT TESTIMONY

OF

DAVID E. DISMUKES, Ph.D.

ON BEHALF OF

SOUTH CAROLINA DEPARTMENT OF CONSUMER AFFAIRS

November 10, 2020

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I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is David E. Dismukes. My business address is 5800 One Perkins Place Drive, Suite 5-F, Baton Rouge, Louisiana, 70808.

Q. WOULD YOU PLEASE STATE YOUR OCCUPATION AND CURRENT PLACE OF EMPLOYMENT?

A. I am a Consulting Economist with the Acadian Consulting Group ("ACG"), a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and non-regulated energy industries. ACG is a Louisiana-registered partnership, formed in 1995, and is located in Baton Rouge, Louisiana.

Q. DO YOU HOLD ANY ACADEMIC POSITIONS?

A. Yes. I am a full Professor, Executive Director, and Director of Policy Analysis at the Center for Energy Studies, Louisiana State University ("LSU"). I am also a full Professor in the Department of Environmental Sciences and the Director of the Coastal Marine Institute in the School of the Coast and Environment at LSU. I also serve as an Adjunct Professor in the E. J. Ourso College of Business Administration (Department of Economics), and I am a member of the graduate research faculty at LSU. Lastly, I also serve as a Senior Research Fellow at the Institute of Public Utilities ("IPU") at the Michigan State University ("MSU") where I regularly teach courses on utility regulation and other energy topics. Appendix A provides my academic curriculum vitae, which includes a full listing of my publications, presentations, pre-filed expert witness testimony, expert reports, expert legislative testimony, and affidavits.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been retained by the South Carolina Department of Consumer Affairs ("DCA") to provide an expert opinion to the Public Service Commission of South Carolina ("Commission") on issues related to Dominion Energy South Carolina's ("DESC" or "Company") proposed class cost of service study ("CCOSS") and its proposed revenue distribution and rate design.

Q. HAS YOUR TESTIMONY BEEN PREPARED BY YOU OR UNDER YOUR DIRECTION AND CONTROL?

A. Yes.

Q. HAVE YOU PREPARED ANY SCHEDULES IN SUPPORT OF YOUR RECOMMENDATIONS?

A. Yes. I have provided 14 schedules in support of my direct testimony that were prepared by me or under my direct supervision.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?

A. My testimony is organized into the following sections:

- Section II: Summary of Recommendations
- Section III: Proposed Rate Increase
- Section IV: Class Cost of Service Study
- Section V: Revenue Distribution
- Section VI: Rate Design
- Section VII: Conclusions and Recommendations

II. SUMMARY OF RECOMMENDATIONS

Q. HAVE YOU PERSONALLY REVIEWED DESC'S APPLICATION AND FILINGS?

A Yes.

Q. WHAT CONCLUSIONS HAVE YOU DRAWN FROM YOUR REVIEW?

A. Yes. Table 1 provides an illustrative comparison of the combined impact on class revenue allocations resulting from my recommended changes to the Company's CCOSS and revenue allocations, relative to the proposed revenue allocations included in the Company's filing.

Table 1: Comparison of Class Revenue Allocations

	Total Jurisdictional Electric	Residential Service	Small Commercial Service	Medium Commercial Service	Large Commercial Service	Lighting Service
DESC Proposed						
Revenue Increase ($ Thousands)	$ 178,233	$ 83,150	$ 35,387	$ 16,700	$ 41,122	$ 1,875
Percentage Increase	8.27%	8.24%	8.31%	8.78%	8.75%	3.13%
Alternative Proposed						
Revenue Increase ($ Thousands)	$ 178,702	$ 78,114	$ 32,977	$ 18,143	$ 44,832	$ 4,636
Percentage Increase	8.29%	7.74%	7.74%	9.53%	9.53%	7.74%

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING THE COMPANY'S CCOSS.

A. I recommend that the Commission adopt an Average and Peak ("A&P") cost allocation method to allocate costs associated with Company production plant facilities. An A&P cost allocation is a blended cost allocation method that recognizes the dual function of electric generation units ("EGUs") in serving both energy and demand needs of an electric system through baseload and peaking facilities. My analysis finds that a substantial portion of the Company's production plant in service is associated with EGUs that operate in a manner to serve baseload energy needs of the Company, including nuclear facilities such as the

Company's V.C. Summer facility. The Company's proposed method, based fully on a coincident peak ("CP") measure of demand, classifies 100 percent of all costs associated with production plant facilities as being demand-related, and is therefore inconsistent with the operations of its generation fleet.

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS REGARDING FUTURE CLASS COST OF SERVICE STUDIES?

A. Yes. I recommend the Commission require the Company to gather monthly system coincident peak information on a class basis in the future. I further recommend that the Commission require the Company to file an alternative CCOSS allocating demand-related electric transmission plant on the basis of the results of a 12 month average of each customer class' contribution to the Company's system monthly coincident peaks ("12-CP") in its next base rate filing. The Company uses the same CP measure of demand used to allocate costs associated with production plant facilities to allocate costs associated with transmission plant facilities. This is inconsistent with the allocation method that is utilized by the Federal Energy Regulatory Commission ("FERC") in deciding appropriate rates for transmission service as well as the methods that are commonly used by other state utility regulators.

Q. WHAT IS YOUR RECOMMENDATION REGARDING PROPOSED CLASS REVENUE ALLOCATIONS?

A. I recommend that the Commission adopt updated class revenue allocations reflecting the proposed alternative CCOSS results presented in Exhibit DED-9. In this alternative CCOSS, I find that medium and large general service customers are currently earning less than the system average rate of return. I therefore assigned a revenue increase to these two classes equal to 1.15 times the overall system average increase of 8.29 percent, or 9.51 percent. I then allocated the remaining required revenue increase equally to all other customer classes. This proposed alternative class revenue distribution reduces the proposed revenue increase to the residential service class from the Company's proposed $83.2 million to $78.1 million, or by approximately $5.0 million.

Q. WHAT ARE YOUR CUSTOMER CHARGE RECOMMENDATIONS AND CONCLUSIONS?

A. I recommend that the Commission reject the Company's proposed increase in customer charges. The Company's proposal would detrimentally impact the public policy goals of promoting energy efficiency. Likewise, it would burden low-use customers with a greater than average portion of any proposed increase in the case.

III. <u>PROPOSED RATE INCREASE</u>

Q. PLEASE SUMMARIZE THE COMPANY'S PROPOSED RATE INCREASE.

A. The Company is requesting an increase in its retail electric rates by approximately $178 million[1] effective on or after March 2021. If approved by the Commission, the Company's proposal will increase residential and total system average rates by 7.73 and 7.75 percent, respectively.[2] The increase for the general service

[1] Direct Testimony of Iris N. Griffin, at 14:18-19.

[2] Direct Testimony of Allen W. Rooks, at pp. 10-15.

classes ranges from 7.2 percent for small general service customers, to 8.68 percent for large general service customers.[3]

Q. DID THE COMPANY EXPLAIN WHY IT IS REQUESTING A RATE INCREASE?

A. Yes. The Company explains it has made an investment of $3.2 billion in assets since its last rate case filing in 2012.[4] Furthermore, in January 2019, the proposed merger of the former SCANA Corporation ("SCANA") and Dominion Energy ("Dominion") closed. This merger resulted in South Carolina Electric and Gas ("SCE&G") reorganizing as Dominion Energy South Carolina, or DESC, which also had implications for DESC's cost of capital relative to its predecessor, SCE&G . DESC explains that in the past, SCE&G issued short-term and long-term debt to support utility operations, which in turn required SCE&G to convert short-term debt to long-term debt to meet covenant requirements on credit facilities.[5] DESC admits that the financial condition of SCANA prior to the merger with Dominion was tenuous with credit downgrades making it difficult to access commercial paper markets.[6] Since the closing of the merger with Dominion, DESC has seen improvements in credit ratings from all three major credit rating agencies relative to that held by SCANA. DESC's debt rating since the merger has improved from speculative ("junk") status held by SCANA to investment-grade.[7]

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[3] Direct Testimony of Allen W. Rooks, Exhibit AWR-1.

[4] Direct Testimony of Iris N. Griffin, at 14:18 to 15:4.

[5] *Id.* at 4:16 to 5:5.

[6] *Id.* at 5:13-15.

[7] *Id.* at pp. 6-7.

Q. HAVE THE COMPANY'S FINANCIAL PROBLEMS PRIOR TO THE MERGER AND REORGANIZATION IMPACTED ITS RATES RELATIVE TO REGIONAL PEER UTILITIES?

A. Yes. [redacted]

Q. HAS THE COMPANY PROVIDED INFORMATION COMPARING ITS RETAIL RATES TO OTHER SELECTED REGIONAL IOUS?

A. Yes. [redacted]

[8] Specifically, Duke Energy South Carolina ("DEC (SC)"), Duke Energy North Carolina ("DEC (NC)"), Duke Energy Progress South Carolina ("DEP (SC)"), and Duke Energy Progress North Carolina ("DEP (NC)").

[9] Company's Response to Data Request DCA Request for Production 1-13.

[redacted]

Q. PLEASE DISCUSS THE GENERAL IMPROVEMENT IN THE COMPANY'S RETAIL RATES RELATIVE TO REGIONAL PEERS.

A. [redacted]

Q. HAVE YOU CONDUCTED YOUR OWN RETAIL RATE BENCHMARKING ANALYSIS?

A. Yes. I have examined the Company's historic retail rates relative to other regional public electric utilities. My analysis shows that the Company's rates, while improving, are still noticeably higher than other regional peer utilities.

Q. PLEASE DISCUSS THE DATA YOU UTILIZED IN YOUR PEER ANALYSIS.

A. My analysis started with the collection of a full decade's worth of Form 1, Annual Report data filed by regulated utilities with the FERC. I examined specific investment and expense trends by major account as defined by the FERC Uniform

System of Accounts ("USOA"). Average revenues (retail revenues divided by sales in megawatt-hour or "MWh" terms) were developed by backing out fuel-related costs from overall sales revenues included in the Form 1.

Q. HOW WERE THE REGIONAL PEER UTILITIES DETERMINED?

A. Peer utilities include investor-owned utilities operating within the states of Mississippi, Alabama, Florida, Georgia, South Carolina, and North Carolina. To this regional group I added the Company's affiliate Dominion Energy Virginia. There are 12 utilities in this regional electric utility peer group, including the Company, used in my statistical benchmarking analysis.

Q. HAVE YOU PREPARED AN EXHIBIT SUMMARIZING YOUR FINDINGS?

A. Yes. Exhibit DED-4 summarizes and compares the historic trends in regional utility residential average base revenues (revenue per kWh) or prices over the past decade. Exhibits DED-5 and DED-6 provide similar comparisons for commercial and industrial customer classes.

Q. WHAT DOES YOUR RESIDENTIAL RATE COMPARISON SHOW?

A. Exhibit DED-4 shows that the Company's residential rates (average base revenues) have been above the average reported for other regional peer utilities every year over the past decade. The Company's ten-year average residential rate of \$0.094/kWh is higher than the peer group's average residential rate of \$0.080/kWh. In the 12-member regional peer group, the Company's residential rates have mostly increased since 2011 to a ranking in 2018 that was almost the highest in the entire peer group (rank 10 out of 12).

Q. DO YOU SEE THE SAME KINDS OF RELATIONSHIPS IN THE COMPANY'S COMMERCIAL RETAIL RATES?

A. Yes. Exhibit DED-5 compares the Company's estimated commercial base rates (average revenues) to regional peer utilities. This analysis shows that the Company's commercial rates are also higher than those of regional peers. The Company's estimated commercial base rates have averaged $0.068/kWh over the past decade, and $0.070/kWh over the past five years compared to a peer average of $0.057/kWh and $0.062/kWh over the comparable two periods, respectively.

Q. HAVE YOU PREPARED A COMPARISON OF THE COMPANY'S INDUSTRIAL RATES RELATIVE TO OTHER REGIONAL PEER UTILITIES?

A Yes. A comparison of the Company's industrial retail rates is provided in Exhibit DED-6. Generally, the Company's industrial rates have been higher than the average for regional peer utilities. In 2010, the Company's average industrial base rate of $0.026 per kWh was slightly lower than the regional average of $0.028 per kWh. This deteriorated over the years such that in 2017 the Company's average industrial rate was $0.042 per kWh, compared to the regional average of $0.035 per kWh.

Q. HAVE YOU ANALYZED THE IMPROVEMENT IN COMPANY RATES SINCE 2018?

A. Yes. DESC's rates improved in the period immediately leading up to the merger of SCANA and Dominion. DESC's 2019 rates appear better situated relative to other regional utilities; however, this is distorted due to a $1.007 billion refund and restitution made to ratepayers covering a prior 11-year period beginning

February 2019. The Company records refunds to customers from what is referred to as a "regulatory liability" that is recorded as a reduction in electric rate operating revenues on its annual FERC Form 1, even though it is refunded to customers through a separate surcharge on customer's bills.[10]

IV. <u>COST OF SERVICE STUDY</u>

A. Introduction

Q. WHAT IS THE PURPOSE OF A CLASS COST OF SERVICE STUDY OR CCOSS?

A. A "CCOSS" reconciles utility costs and revenues across different customer classes. The goal of a CCOSS is to determine the cost of providing service and revenue responsibility for each individual customer class. CCOSS results are used to estimate class specific rates of return and can serve as a guidepost for class revenue responsibilities and ultimately rates.

Q. HOW IS A CCOSS PREPARED?

A. A CCOSS utilizes a set of historic or projected cost information which is (1) "functionalized," (2) "classified," and (3) "allocated." The functionalization process simply categorizes costs based upon the functions they serve within a utility's overall operations (i.e. production, transmission, and distribution). The classification process characterizes costs by "type" including those that are (1) demand-related, (2) energy-related, or (3) customer-related. The last step of the process "allocates" each of these costs to a respective jurisdiction or customer class as appropriate.

[10] Company's 2019 FERC Form 1.

Q. CAN YOU EXPLAIN WHAT YOU MEAN BY DEMAND-RELATED COSTS?

A. Yes. Demand-related costs are associated with meeting maximum electricity demands. At the distribution level, electric substations and line transformers are designed, in part, to meet the maximum customer demand requirements. At the production level, most power plants or EGUs are typically viewed as being designed to serve both energy and demand/capacity needs of the utility. The exact degree of this split between energy and demand functionality depends on the individual EGU in question and its place in a utility's dispatch curve, with more baseload units serving more of the utility's energy needs and more peak units serving more of the utility's capacity or demand needs. Therefore, it is not uncommon to develop composite energy and demand allocators to allocate plant in service costs associated with a utility's generation fleet.

Q. HOW ARE ENERGY-RELATED COSTS DEFINED?

A. Energy-related costs are defined as those that tend to change with the amount or volume of electricity (i.e., kWh) sold. Electric generation costs and high-voltage transmission lines, for instance, can be allocated, in part, based on some measure of electricity sales.

Q. WHAT ABOUT CUSTOMER-RELATED COSTS?

A. Customer-related costs are those associated with connecting customers to the distribution system, metering household or business usage, and performing a variety of other customer support functions.

Q. PLEASE EXPLAIN THE COST CLASSIFICATION PROCESS.

A. After all costs have been identified by functional type ("functionalization"), a CCOSS then classifies costs based on the appropriate measure associated with each particular cost type. For example, most costs are classified based on their relationship to system demand measured as either coincident peaks ("CP") or non-coincident peaks ("NCP"). CP demand measures evaluate each class' contribution to overall system peak demand, while NCP demand measures evaluate each class' peak demand irrespective of the wider system requirements. CP demand measures are typically used in the allocation of costs associated with transmission and distribution facilities with significant diversity of loads present, while NCP measures of demand are used in the allocation of costs associated with transmission and distribution facilities that serve less diversified loads. Likewise, customer related costs may be allocated based on the number of customer accounts, or weighted customer metrics such as weighted cost of installed meters to allocate costs associated with meter reading.

Q. PLEASE EXPLAIN THE ALLOCATION PROCESS.

A. A CCOSS then uses the information from the prior two steps (functionalization, classification) to allocation costs to customer classes or, in some cases, operating jurisdictions.

Q. IS THE ALLOCATION PROCESS RELATIVELY STRAIGHTFORWARD ?

A. No. Some costs can be clearly identified and directly assigned to a function or category, while other costs are more ambiguous and difficult to assign. The primary challenge in conducting a CCOSS is the treatment of what are known as "joint and common" costs. Given their shared or integrated nature, these joint and common costs can often be difficult to compartmentalize. Therefore, unique allocation factors are utilized in a CCOSS to classify joint and common costs. The process of developing these cost allocation factors can become subjective and is often imbued with policy considerations. For example, investments to improve distribution system reliability provide the most benefit to large industrial and commercial customers whose workflow is negatively impacted by service interruptions, though distribution systems themselves are typically viewed as being designed to meet peak system demand requirements that are often driven by residential and small commercial loads. Likewise, growth caused by new or expanded industrial needs may require investment in utility systems to serve systems that again are typically themselves viewed as being designed to meet peak system demand requirements that are often driven by residential and small commercial loads.

Q. HOW DOES A CCOSS RELATE TO COMMONLY QUOTED ECONOMIC PRINCIPLES?

A. A CCOSS is also referred to as a "fully allocated cost study" since it allocates test year revenues, rate base, expenses, and depreciation to various jurisdictions and customer classes based upon a series of different allocation factors. The purpose of the CCOSS is to develop cost responsibility estimates for each customer class, which in turn, can be used to develop rates. A CCOSS is based upon a set of historic utility book costs that have accumulated over decades. Rates are, therefore, based upon historic average costs; whereas economic theory suggests that the most efficient form of pricing in perfectly competitive markets should be based upon marginal costs. However, regulated utilities do not operate in perfectly competitive markets and, by their very nature, are natural monopolies. Thus, reaching the ideal pricing formula outlined in economic theory is impossible since the nature of natural monopolies makes pricing in the presence of declining average costs, coupled with the presence of joint and common costs, difficult.

Q. ARE THERE ANY OTHER CONFOUNDING PROBLEMS THAT CAN ARISE WITH A CCOSS?

A Yes. There is also an issue with the fact that the cost information utilized in a CCOSS are usually historic and static, not dynamic and forward-looking. These analytic deficiencies undermine many experts' cost causation/pricing claims. As a result, in regular practice there is no single correct answer that is revealed in a CCOSS. It is often up to regulators to exercise an appropriate level of judgment regarding the nature of these costs, the results of the CCOSS, and the implications both have in setting fair, just, and reasonable rates. This is one of the reasons why many regulators use CCOSS results as a "guide" in setting rates and are not bound by their results.

Q. WHAT CONTROVERSIES ARISE IN THE ANALYSIS AND COMPARISON OF VARIOUS CCOSS METHODOLOGIES?

A. The CCOSS process is significantly different than the revenue requirement or cost of capital phase of a typical rate case. While the latter two activities are dedicated to determining the amount of revenue that will be recovered through rates, the CCOSS process determines how those costs (revenue requirements) will be recovered through customer rates. The primary controversy with the evaluation of various CCOSS results often rests with determining whether costs (revenue requirements) will be recovered by the relative customer share of each class, the peak load contributions of each customer class, or whether and how the approach will be tempered through the use of customer, peak, and off-peak usage considerations. Methodologies that are heavily skewed toward customer and peak considerations, for instance, can tend to shift costs more than proportionally to relatively lower load-factor customers, such as residential and small commercial customers. These approaches can also fail to capture the service being provided by the utility (i.e., electric service in this case), and how the value of that service varies by the amount purchased by different customer classes.

Q. PLEASE EXPLAIN WHY METHODOLOGIES THAT ARE SKEWED TOWARD PEAK CONSIDERATIONS SHIFT COSTS TOWARDS LOWER LOAD-FACTOR CUSTOMERS SUCH AS RESIDENTIAL AND SMALL COMMERCIAL CUSTOMERS.

A. A large portion of residential and small commercial customer electricity loads in the U.S. are associated with weather sensitive air conditioning loads. Larger industrial customers, on the other hand, use electricity within industrial processes that are not weather sensitive. Because of this, daily and annual usage patterns for these two customer classes are significantly different. The peak loads for residential and small commercial customers tend to be more peaked than those for industrial customers, which are more steady and evenly distributed across peak and non-peak hours. For example, an average residential customer has relatively little electricity use during overnight hours and during weekday day-time working hours. Residential customers do exhibit relatively significant use during early summer evening hours corresponding to returning home from work, and potentially during chilly early winter morning hours if the customer uses electric resistance heating, as commonly seen in southern U.S. climates. Similarly, small commercial customers see limited electricity use outside of workday hours.

Q. DO THESE USAGE BEHAVIORS DIFFER FROM LARGE INDUSTRIAL CUSTOMERS?

A. Yes. Large industrial customers utilize electricity within industrial processes with little weather sensitive loads. Thus, industrial loads tend to be more evenly distributed across the hours of the day, depending upon plant or facility operations. Since these loads are not weather sensitive, there are usually limited differences between industrial summer and winter usage patterns. These customer classes are typically viewed as having high load factors, with peak energy demands relatively consistent to average daily and annual energy demands. This differs from residential customers which tend to have lower load factors given the wide differences between their average and peak loads.

Q. PLEASE DEFINE WHAT IS MEANT BY A "LOAD FACTOR."

A. A load factor is defined as the ratio of the average load in kilowatt hours supplied during a designated period to the peak or maximum load in kilowatts occurring in that period. The load factor is expressed as a percentage and may be derived by taking the energy used during a period and dividing by the product of the maximum demand and the number of hours in the period.

$$Annual\ Load\ Factor =$$

$$Annual\ kWh\ Energy\ Use \Big/ (Peak\ kW\ Use * 8760\ Hours)$$

A system that is estimated to have a high load factor is often thought to be utilizing electricity more efficiently since usage is consistent and does not swing largely between average and peak periods. Conversely, systems with low load factors must maintain idle capacity in order to meet the relatively large swings in load between average and peak periods.

Q. IS IT PREFERABLE TO PROMOTE THE DEVELOPMENT OF HIGHER LOAD FACTORS?

A. Yes, as higher load factors are indicative of more efficient utilization of system resources. However, it should be recognized that all utilities inherently have customers with different load profiles due to differences in how the customer uses electricity. Furthermore, the development of integrated wholesale bulk electricity transmission systems has allowed utilities to collectively diversify generation resources and individual system demands, which has reduced the impact of individual system load characteristics on generation needs in recent years. While rates should recognize and promote the efficiency utilization of utility system resources, one should caution placing too much emphasis on this principle rewarding high load factor industrial customers to the detriment of low load factor residential and small commercial customers.

Q. DO UTILITIES HAVE A VESTED INTEREST IN ALLOCATING COSTS AWAY FROM HIGHER USE CUSTOMERS SUCH AS INDUSTRIAL CUSTOMERS?

A. Yes. Higher use customers such as industrial customers are inherently more price sensitive than lower use customers due to the relative impact increases in rates can have on these customers' total utility bills and the margins of produced goods. These higher use industrial customers tend to have more energy supply alternatives that can include fuel switching and self-generation which is part of the reason why they are more price sensitive. Thus, utilities can have incentives to assign cost and revenue responsibilities away from larger price sensitive customers and onto those with fewer alternatives such as the residential and smaller commercial customer classes.

Q. WHAT IS A POTENTIAL MANNER IN WHICH A CCOSS CAN BE BIASED AGAINST LOWER LOAD-FACTOR CUSTOMERS?

A. Utilities by their nature are capital intensive industries with high degrees of capital expenditures required to develop systems to generate and transmit power to customers relative to annual expenses associated with administrative operations. Therefore, deciding the appropriate allocation of costs associated with utility capital investments (e.g., utility "plant in service") largely affects the cost of providing service. Utilities can often over-emphasize peak demand factors in allocating these large plant costs in order to assign more costs away from their price sensitive customers. Likewise, utilities can emphasize non-diversified single CP demands, NCP demands, and individual customer demands in allocating costs associated with transmission and high voltage distribution plant facilities to favor high-load factor customers relative to low-load factor customers. Finally, utilities can over-emphasize customer connection aspects of lower voltage distribution facilities to favor high-use customers relative to low-use customers.

B. Company's CCOSS

Q. PLEASE DESCRIBE THE COMPANY'S CCOSS.

A. First, the Company grouped all its costs into major groups. These groups were then functionalized into production, transmission, distribution, or customer- related costs.[11] Next, the groups were classified as either demand, energy, or customer-related costs.[12] The Company then developed allocation factors based on kW, kWh, and the number of customers, to allocate cost components to the various retail customer classes.[13]

Q. PLEASE DESCRIBE THE DEMAND ALLOCATORS USED WITHIN THE COMPANY'S CCOSS.

A. The Company utilizes a CP cost allocation method in allocating its production plant and transmission plant investments. This method employs an approach that uses the average of the system peak demand between the hours of 2 p.m. and 6 p.m. on the chosen peak demand day.[14] For the test year, the Company states that its peak demand occurred on July 18, 2019.[15] For distribution plant investments, the Company utilizes a cost allocation based on relative class NCPs.

Q. HAVE YOU PREPARED A SUMMARY OF THE RESULTS OF THE COMPANY'S CCOSS?

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[11] Direct Testimony of Kevin R. Kochems, at 14:7-8

[12] Direct Testimony of Kevin R. Kochems, at 14:9-10

[13] Direct Testimony of Kevin R. Kochems, at 16:19-20

[14] Direct Testimony of Kevin R. Kochems, at 17:13-15

[15] Direct Testimony of Kevin R. Kochems, at 18:10-11.

A. Yes, and this summary is presented as Exhibit DED-7. The Company finds that it earned a system average rate of return during the test year of 6.00 percent, or 6.16 percent on a retail basis. The Company also finds that class-based rate of return ranges from 4.61 percent for the large general service customer class, to 8.82 percent for street lighting customers. The Company's test year residential class returns are estimated to be 5.99 percent, which approximates its system-average rate of return.

Q. DO YOU DISAGREE WITH ANY OF THE ASSUMPTIONS OR ALLOCATION FACTORS INCORPORATED IN THE COMPANY'S PROPOSED CCOSS?

A. Yes. I disagree with the Company's CCOSS cost allocation method related to the classification of production plant. The Company's allocation method places too great an emphasis on class peak contribution relative to annual energy use and does not reflect the function production facilities serve in the provision of electric service. In addition, it should be noted that the Company's cost allocation for costs associated with transmission plant facilities is inconsistent with the method utilized by FERC in establishing transmission rates.

C. Production Plant Classification

Q. WHAT FUNCTIONS DO PRODUCTION FACILITIES SERVE?

A. EGUs are designed to serve both energy and demand/capacity needs of a utility. The exact degree of this split between energy and demand functionality depends on the individual EGU in question and its place in the utility's dispatch curve. EGUs defined as baseload units are designed with low operating costs in mind and are thus designed to operate during most hours of the year. EGUs defined as peaking units, on the other hand, are designed with additional operational flexibility relative to baseload units in mind, specifically in the ability of the units to quickly and cost effectively "start-up." Peaking units are typically held in reserve and only utilized by a utility during periods of peak demand when the utility requires additional generation resources not required during lower demand periods. These functional differences impact the function the EGU provides to a utility's energy system, with EGUs defined as baseload serving more of a utility system's energy needs while EGUs defined as peaking units serve more of the utility's demand/capacity needs. It is therefore not uncommon to develop composite energy and demand allocators that represent this mixed use and classification. It is therefore not uncommon to use hybrid demand and energy cost allocation methods such as the "A&P" cost allocation methodology, to account for this dual function.

Q. PLEASE DESCRIBE AN A&P COST ALLOCATION METHODOLOGY.

A. An A&P cost allocation methodology is based upon a two-component weighted average. The first component represents each rate class' share of a utility's total annual energy sales, and the second component represents each rate class' share of a utility's annual system peak demand. These components are combined through a weighted average through the use of system load factor. Specifically, the energy component of the calculation is weighted by the utility's overall system load factor while the peak demand component is weighted by the inverse of the system load factor (*i.e.*, 1 minus the system load factor).

Q. ARE THERE WAYS TO EVALUATE THE FUNCTION AN INDIVIDUAL EGU PROVIDES TO A UTILITY'S ELECTRICAL SYSTEM?

A. Yes. The most basic method is an examination of individual units' 'capacity factor.' The capacity factor is the measure of an EGUs output over a period of time compared to its maximum potential output.

$$Annual\ Capacity\ Factor = \frac{Annual\ MWh\ Generation}{(Nameplate\ MW\ Capacity * 8760\ Hours)}$$

Units with a high capacity factor operate at high utilization, operating for more hours of the year than units with a low capacity factor and are associated with baseload generation units. Units with a lower capacity factor are held in reserve by utilities for more hours for operational or economic reasons. In this manner, capacity factor can be thought of conceptually similar to load factors, just applied to examinations of the generation output of EGUs as opposed to examining the demand patterns of system demands.

Q. HAVE YOU CONDUCTED ANY ANALYSIS OF THE RELATIVE CLASSIFICATION OF INDIVIDUAL COMPANY GENERATION UNITS?

A. Yes. Exhibit DED-8 presents the result of an analysis of the gross plant in service of each of the Company's EGUs and the unit's capacity factor during the test year to characterize the role the unit serves in the Company's dispatch of electricity. All facilities with annual capacity factors less than 10 percent were assumed to be fully classified as serving the utility's demand requirements, while all other facilities were divided between energy and demand classifications based on the unit's capacity factor. This means that the Company's ownership stake in the V.C. Summer nuclear facility, which had a 91.5 percent capacity factor during 2019, was classified as 91.5 percent energy-related and 8.5 percent demand-related.

Q. WHAT ARE THE RESULTS OF YOUR ANALYSIS OF THE RELATIVE CLASSIFICATION OF INDIVIDUAL COMPANY GENERATION UNITS?

A. Exhibit DED-8 finds that a substantive portion of the Company's 2019 gross plant in service is devoted to the provision of energy and not directly associated with meeting the Company's demand-needs. Specifically, I find that 48.3 percent, or nearly half, of the Company's 2019 gross plant in service is appropriately classified as being energy-related, and 51.7 percent appropriately classified as being demand-related. This is significantly different than the Company's proposed classification, which fully classifies production plant facilities as demand-related.

Q. WHAT IS YOUR RECOMMENDATION REGARDING PRODUCTION PLANT COST ALLOCATION IN THE COMPANY'S PROPOSED CCOSS?

A. I recommend that the Commission adopt an A&P allocation method in place of the Company's current CP cost allocation method. The Company's CP cost allocation method classifies 100 percent of all costs associated with production plant facilities as being demand-related. My analysis finds that a significant portion of the Company's production plant fleet is devoted to serving energy needs of the Company, and not solely demand needs. Therefore, the Company's current classification approach is inconsistent with the operations of its generation fleet.

Q. HAVE YOU ESTIMATED THE EFFECT ON THE RELATIVE CLASS RATES OF RETURN USING THE MODIFIED COST ALLOCATION APPROACH FOR PRODUCTION PLANT FACILITIES?

A. Yes. The results of this alternative CCOSS are presented in Exhibit DED-9. I find that residential, small commercial, and lighting service customers are currently paying above cost of service rates and subsidizing medium and large commercial service customer rates.

Table 2: Comparison of CCOSS Results

	Total Electric	Total Jurisdictional Electric	Residential Service	Small Commercial Service	Medium Commercial Service	Large Commercial Service	Lighting Service
DESC Proposed							
Rate of Return	6.00%	6.16%	5.99%	7.59%	5.74%	4.61%	8.82%
Relative Rate of Return	1.00	1.03	1.00	1.26	0.96	0.77	1.47
Alternative Proposed							
Rate of Return	6.00%	6.15%	6.93%	8.35%	5.36%	2.32%	7.04%
Relative Rate of Return	1.00	1.02	1.16	1.39	0.89	0.39	1.17

D. Allocation of Transmission Plant

Q. HOW DOES THE COMPANY CLASSIFY AND ALLOCATE COSTS ASSOCIATED WITH TRANSMISSION PLANT FACILITIES?

A. The Company uses the same CP cost allocation method to classify and allocate costs related to transmission plant facilities as it does for costs related to production plant facilities. Therefore, the Company fully classifies transmission plant facilities as related to the provision of capacity or system demand on its system.

Q. IS THE COMPANY'S CLASSIFICATION OF ITS TRANSMISSION SYSTEM AS FULLY RELATED TO THE PROVISION OF SYSTEM DEMAND NEEDS PROBLEMATIC?

A. No. Plant facilities below the production level involved in the transmission and distribution of electric power to customers, exclusive of customer-specific service drops, are typically classified as fully demand-related. Higher-level facilities, such as transmission, are viewed as associated with satisfying broad system-wide demands, while facilities located nearer to customers, such as primary and secondary distribution lines, are viewed as satisfying more localized demands. The Company distinguishes between these functions by using a CP cost allocation approach to allocate costs associated with transmission plant facilities, and an NCP cost allocation approach to allocate costs associated with distribution plant facilities.

Q. IS THERE A POTENTIAL ISSUE ASSOCIATED WITH THE COMPANY'S CP COST ALLOCATION APPROACH FOR COSTS RELATED TO TRANSMISSION PLANT FACILITIES?

A. Yes. The Company's CP cost allocation approach is based on the four-hour average CP during the single day of the test year where the Company experienced its maximum system peak for the year. This is inconsistent with the approach used by FERC in developing electric transmission rates. Specifically, FERC uses what is referred to as a 12-CP approach, which is the average of all 12 monthly system CP during an annual period. This method is also used by many state regulators to assure consistency in the cost allocation of transmission facilities between retail and wholesale jurisdictions.

Q. HAVE YOU EVALUATED THE RESULTS OF THE COMPANY'S USE OF A CP ALLOCATION TO ALLOCATE COSTS ASSOCIATED WITH TRANSMISSION PLANT FACILITIES?

A. No. In response to discovery the Company responded that it does not calculate coincident peak contributions by class on a monthly basis.[16] Without monthly system CP information on a class basis it is impossible to calculate the 12-CP

[16] Company's Response to DCA Request for Production 1-25.

approach used by FERC to allocate costs associated with electric transmission assets.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S ALLOCATION OF COSTS ASSOCIATED WITH ELECTRIC TRANSMISSION ASSETS?

A. I recommend the Commission require the Company to gather monthly system coincident peak information on a class basis in the future. I further recommend that the Commission require the Company to file an alternative CCOSS allocating demand-related electric transmission plant on a 12-CP basis in its next base rate filing.

V. <u>REVENUE ALLOCATION</u>

Q. PLEASE EXPLAIN THE PURPOSE OF THE REVENUE ALLOCATION PROCESS IN SETTING RATES.

A. The revenue allocation or revenue distribution process allocates a utility's overall revenue deficiency across customer classes, which in turn, is used to establish a new set of retail rates. The revenue distribution process often uses the results from the CCOSS as its starting point, but not necessarily as its ending point. Class-specific revenue responsibilities are established by allocating the system-wide revenue deficiency to classes that are under-earning, relative to their estimated ROR, and assigning, at least in theory, revenue decreases to those classes that are over-earning relative to their CCOSS-estimated class returns. The final class revenue responsibilities are then used, in conjunction with each class' billing determinants, to determine rates. In summary, the revenue distribution process can be thought of as the initial step taken to establish rates.

Q. DOES THE REVENUE DISTRIBUTION PROCESS INCLUDE ANY POLICY CONSIDERATIONS?

A. Yes. Allocating the overall system-wide revenue deficiency entirely on a full cost of service basis can result in a very significant and adverse rate impact for certain under-earning classes. To avoid such a result, regulators often temper the revenue responsibilities assigned to various customer classes in order to meet a set of broad ratemaking policy goals.

Q. WHAT ARE THOSE BROADER RATEMAKING POLICY GOALS?

A. There are several generally-accepted rate-making principles used in utility regulation that include:

1) Rates should be fair, just, and reasonable, and not unduly discriminatory.
2) To the extent possible, gradualism should be used to protect customers from rate shock.
3) Rate continuity should be maintained.
4) Rates should be informed by costs, but class cost of service results need not be the only factor used in rate development.
5) Rates should be understandable to customers.

Q. HOW ARE THE ABOVE PRINCIPLES APPLIED IN DEVELOPING RATES FOR A REGULATED UTILITY?

A. It is important to consider all of the principles I mentioned above. However, any principle's relative weight can change depending upon the importance of certain policy goals. Rate design should strike a balance between policy goals and result in rates that are fair, just, and reasonable. There is no pre-set or universallyaccepted formula for developing rates and, as a result, judgment is necessary to formulate a rate design that meets these objectives.

Q. WHAT ARE THE COMPANY'S OBJECTIVES UNDERLYING ITS PROPOSED RATE DESIGN?

A. The Company states that its overall rate design objective is to develop fair rates that also allow it to earn an adequate return for its investors.[17] The Company also states that it attempts to (1) maintain a reasonable level of simplicity in rates,[18] (2) design rates to provide clear market signals to promote the efficient use of electricity, specifically encourage off-peak use and higher load factors,[19] (3) design rates to help customers' efficiency and ability to compete in domestic and foreign markets,[20] and (4) design rates that encourage new customers to locate in South Carolina as well as retain existing customers.[21]

Q. PLEASE EXPLAIN HOW THE COMPANY PROPOSES TO DISTRIBUTE ITS CLASS REVENUE REQUIREMENTS.

A. The Company first examined the results of its CCOSS before developing proposed class revenue requirement distributions. The Company assumed a 9.0 percent overall retail rate of return which equated to an overall 7.0 percent revenue increase.[22] The Company then adjusted rates for each class such that each class

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17 Direct Testimony of Allen W. Rooks at 4:4-5.

18 *Id.* at 4:6-7.

19 *Id.* at 4:8-10.

20 *Id.* at 4:11-13.

21 *Id.* at 4:13-14.

22 Direct Testimony of Kevin R. Kochems at 21:13-14.

return equaled 9.0 percent during the test year.[23] The Company however recognizes the Commission's historic practice that a reasonable relationship exists between classes so long as each customer class falls within 10 basis points of the system average in terms of a Unitized Rate of Return or Relative Rate of Return ("RROR").[24] Therefore, the Company utilized judgments in distributing its proposed increase to the small general service class, which was found to have a RROR slightly less than 0.9, and the Lighting classes, which was found to have a RROR slightly greater than 1.1.[25]

Q. WHAT DO YOU MEAN BY A RROR?

A. The RROR effectively standardizes the class-specific rate of return estimated by a CCOSS to the overall system average. In other words, it divides the estimated class rate of return ("ROR") by the estimated system ROR. For instance, assume that the residential class is earning a class-specific eight percent ROR and further assume that the system-wide average ROR estimated by the same CCOSS is also eight percent. The residential class, in this example, can be said to be earning a 1.0 RROR if the estimated ROR is the same as the overall system (*i.e.*, eight percent divided by eight percent equals 1.0). Put another way, any class earning a 1.0 RROR can be said to be making its full contribution to the system's overall ROR (*i.e.*, there is no cross-subsidy). A RROR that is greater than one indicates that a particular class is contributing more than the system average contribution to

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[23] *Id.* at 21:15-17.

[24] *Id.* at 21:18 to 22:12.

[25] *Id.* at 22:13-20.

the Company's overall return. Likewise, a class that earns a RROR less than 1.0 but greater than zero can be said to be making a less-than-average contribution to the overall system, and is effectively being partially subsidized by other classes. A class earning a RROR that is less than zero (*i.e.*, a negative RROR) is usually considered an anomaly, and indicates that such a class is being more than fully subsidized by other customer classes.

Q. DO YOU AGREE THAT A CLASS RROR LESS THAN 1.0 IS PROBLEMATIC OR INEQUITABLE?

A. Not necessarily. There may be policy reasons to support such a result which underscore why a result of this nature may not indicate an inequitable cross-subsidization. For example, the presence and/or continuation of a RROR below one could be the result of a prior agreed-upon rate freeze that prevents class rates from increasing to correct the revenue deficiency (relative to cost of service). In this example, the presence of a below one RROR is simply a function of a prior policy decision, not necessarily the result of some arbitrary or intentionally-designed inequity. Therefore, I do not agree that cross-subsidization automatically means that such subsidization is problematic or inequitable. Nonetheless, it is typically viewed as preferential that rate of return at least approximate the cost to provide service.

Q. HAVE YOU PREPARED A SUMMARY OF THE COMPANY'S PROPOSED REVENUE DISTRIBUTION?

A. Yes. Exhibit DED-10 presents a summary of the Company's proposed class revenue distributions relative to its cost of service findings. The Company's proposed rate increases generally fall between 8.24 percent for the residential customer class, and 8.78 percent for medium general service customers. The sole exception is the Company's proposed increase to lighting classes, which the Company's proposes to increase by 3.13 percent. This reflects the Company's finding of a RROR of 1.43 for lighting classes.

Q. WHAT IS YOUR RECOMMENDATION REGARDING PROPOSED CLASS REVENUE DISTRIBUTIONS?

A. I recommend that the Commission adopt updated class revenue distributions reflecting the proposed alternative CCOSS results presented earlier. In this alternative CCOSS, I find that medium and large general service customers are currently earning less than the system average rate of return. I therefore assigned a revenue increase to these classes equal to 1.15 times the overall system average increase of 8.29 percent, or 9.53 percent. I then allocated the remaining required revenue increase equally to all other customer classes.

Q. HAVE YOU PREPARED A SUMMARY OF THE EFFECTS OF YOUR PROPOSED REVENUE DISTRIBUTION?

A. Yes. My proposed alternative revenue distribution is presented in Exhibit DED-11. My proposed revenue distribution would lower the proposed increase in base rates to residential customers to 7.74 percent, compared to the Company's proposed increase to these same customers of 8.24 percent. When accounting for the proposed increase in the storm damage component and reduction in DSM component, my proposed revenue distribution results in a 7.23 percent net increase in rates to residential customers, compared to the Company's proposed

7.73 percent increase.

Table 1: Comparison of Class Revenue Allocations

	Total Jurisdictional Electric	Residential Service	Small Commercial Service	Medium Commercial Service	Large Commercial Service	Lighting Service
DESC Proposed						
Revenue Increase ($ Thousands)	$ 178,233	$ 83,150	$ 35,387	$ 16,700	$ 41,122	$ 1,875
Percentage Increase	8.27%	8.24%	8.31%	8.78%	8.75%	3.13%
Alterantive Proposed						
Revenue Increase ($ Thousands)	$ 178,702	$ 78,114	$ 32,977	$ 18,143	$ 44,832	$ 4,636
Percentage Increase	8.29%	7.74%	7.74%	9.53%	9.53%	7.74%

VI. RATE DESIGN

A. Rate Design Objectives

Q. PLEASE DESCRIBE THE MAJOR COMPONENTS OF ELECTRIC UTILITY RATES.

A. Electric utility rates are typically comprised of three basic elements. The first component is the fixed monthly customer charge sometimes referred to as a basic service charge or a basic facility charge. The second is the energy-based component that is a volumetric rate applied toward a customer's monthly energy usage during a billing period, often measured in terms of kWh. Finally, demand rates are surcharges that are assessed based upon a customer's maximum usage during a billing period, commonly measured in terms of kW for those customers that are demand metered. Historically some smaller use customer classes, such as residential and small commercial classes, are not demand-metered and thus, only face customer and energy charges. Customers with just customer and energy charges have bills that are based upon what is commonly called a "two-part tariff" (e.g., energy and customer charge) whereas large demand metered customers face a "three part tariff" (e.g., energy, customer, and demand charges).

Q. HOW SHOULD POLICY BALANCE COST ASSIGNMENTS BETWEEN CUSTOMER CHARGES AND VOLUMETRIC RATES?

A. Modern utility pricing theory is primarily concerned with the development of optimal tariff design, which over the years has become dominated by the two-part and three-part tariff form discussed previously, that is sometimes referred to more technically as a non-linear (or non-uniform) pricing approach. Once a class revenue requirement is established, the goal for regulators should be one that sets the most appropriate rates based upon various efficiency and equity considerations. Balancing the weight of how costs are recovered between fixed rates, variable rates, block rates, and seasonal rates are all integrated parts of that process.

Q. WHAT IS THE APPROPRIATE ROLE OF COSTS IN SETTING RATES FOR A TWO-PART TARIFF?

A. Costs can be instructive in establishing a baseline upon which prices may be set, but costs do not need to serve as the sole or exclusive basis for rates in order for them to be set optimally (*i.e.,* fixed charges do not need to strictly equal fixed costs, variable rates need not strictly equal variable costs). Unfortunately, the "fixed charge-equals-fixed cost" philosophy gets repeated so often that it can often drown out meaningful discussions about other equally important considerations in setting rates in imperfect markets. In fact, appropriate rate setting in the context of a two-part tariff typically has more to do with consumer demand than it does with cost.

B. Customer Charge Proposals

Q. PLEASE DISCUSS THE COMPANY'S CUSTOMER CHARGE PROPOSALS.

A. A summary of the Company's current and proposed customer charges has been provided in Exhibit DED-12. The Company states that it is "keenly aware" of the sensitivity of customer charge, or Basic Facilities Charge ("BFC"), increases on low use residential customers.[26] However, the Company states that it also believes that it is important to increase these charges to reflect actual customer-related costs. The Company proposes to increase the BFC for its residential customers by $2.50 per month,[27] or approximately 27.8 percent. The Company proposes to temper this proposed increase for customers taking service on the low use residential service rate schedule to $1.25 per month, or half of the proposed increase to other residential rate schedules.[28]

Q. HAVE YOU COMPARED THE COMPANY'S PROPOSED RESIDENTIAL CUSTOMER CHARGES TO OTHER REGIONAL ELECTRIC UTILITIES?

A. Yes, and this analysis is presented in Exhibit DED-13. This analysis shows that the Company's current BFC of $9.00 per month for residential customers, while lower than the regional average of $12.93 per month, is not the lowest customer charge in the region. Specifically, there are three utilities operating in the region that currently charge residential customers a lower monthly customer charge compared to the Company. These include Dominion Virginia Power, Entergy

[26] Direct Testimony of Allen W. Rooks at 7:7-9.

[27] *Id.* at 7:14-15.

[28] *Id.* at 7:20 to 8:1.

Mississippi, and Florida Power and Light. The Company's Virginia affiliate, Dominion Virginia Power, currently charges its residential customers a monthly customer of $6.58 per month, which is 26.9 percent less than that charged by the Company. If the Company's proposed increase to residential BFC was accepted, the Company's customer charge would be greater than six of the 13 regional electric utilities.

Q. HAVE YOU COMPARED THE COMPANY'S COMMERCIAL CUSTOMER CHARGES TO OTHER REGIONAL ELECTRIC UTILITIES?

A. Yes. The Company's current small commercial BFC of $19.50 per month is reasonably consistent with the average commercial customer charge of $19.69 for other regional utilities. Out of 13 electric companies surveyed in Exhibit DED-13, only four have a customer charge for commercial customers that is greater than the Company's current BFC. Further, the Company's proposed small commercial BFC of $22.00 per month would be greater than that for all but three regional electric utilities.

Q. IS THE COMPANY'S PROPOSAL TO INCREASE CUSTOMER CHARGES CONSISTENT WITH THE PROMOTION OF ENERGY EFFICIENCY AND CONSERVATION?

A. No. The Company's rate design proposal is inconsistent with energy efficiency since it reduces economic incentives for ratepayers to control monthly utility bills through energy efficiency and conservation efforts, because only the variable component of bills is avoidable. As an extreme example, consider a straight-fixed-variable ("SFV") rate design where customers pay the same charge for non-energy related activities regardless of their usage level. As a result, inefficient customers would pay the same monthly utility bill as relatively more efficient customers, negating all incentive to seek greater efficiency.

Q. HAVE OTHER COMMISSIONS RECOGNIZED THE DETRIMENTAL EFFECT INCREASED FIXED CHARGES HAVE ON ENERGY EFFICIENCY?

A. Yes. In rejecting a request by Baltimore Gas and Electric ("BGE") to increase customer charges as part of a larger rate design proposal, the Maryland Public Service Commission recognized the need to allow customers the opportunity to control their monthly bills by reducing energy usage.

> Even though this issue was virtually uncontested by the parties, we find we must reject Staff's proposal to increase the fixed customer charge from $7.50 to $8.36. Based on the reasoning that ratepayers should be offered the opportunity to control their monthly bills to some degree by controlling their energy usage, we instead adopt the Company's proposal to achieve the entire revenue requirement increase through volumetric and demand charges. This approach also is consistent with and supports our EmPOWER Maryland goals.[29]

Q. IS THE MARYLAND COMMISSION ALONE IN ITS BELIEF THAT HIGH FIXED CHARGES DISCOURAGE EFFICIENT USE OF ENERGY?

A. No. A research document presented for consideration by the membership of the National Association of Regulatory Utility Commissioners ("NARUC") lists SFV rate design as an alternative to delink utility revenue from sales. An SFV places all fixed costs into fixed charges while relegating only variable costs to volumetric

[29] Maryland Public Service Commission Case No. 9299, In the Matter of the Application of Baltimore Gas and Electric Company for Adjustment in its Electric and Gas Base Rates (*"Case No. 9299")*. Order No. 85374 at p. 99, rel. February 22, 2013.

rates. The NARUC research noted this type of rate design was problematic because of its effects on customer incentives to conserve energy:

> **Straight-Fixed Variable Rate Design.** This mechanism eliminates all variable distribution charges and costs are recovered through a fixed delivery services charge or an increase in the fixed customer charge alone. With this approach, it is assumed that a utility's revenues would be unaffected by changes in sales levels if all its overhead or fixed costs are recovered in the fixed portion of customers' bills. This approach has been criticized for having the unintended effect of reducing customers' incentive to use less electricity or gas by eliminating their volumetric charges and billing a fixed monthly rate, regardless of how much customers consume.[30]

Q. HAS ANY NATIONAL PUBLIC POLICY ANALYSIS NOTED THE EFFICIENCY DISINCENTIVES ASSOCIATED WITH SFV-TYPE RATE DESIGNS?

A. Yes. The National Action Plan for Energy Efficiency ("NAPEE"), a joint venture of the U.S. Department of Energy and U.S. Environmental Protection Agency, published a whitepaper on various rate design effects on encouraging energy efficient behaviors. The NAPEE postulated that SFV had a detrimental effect on economic signals to encourage customers to change energy usage behavior and investments in energy efficiency devices, and specifically noted that such disincentives persist even when applied to individual components of a customer's utility bill, such as SFV for strictly distribution services:

> Because [SFV] tends to shift costs out of volumetric charges, it tends to reduce customers' efficiency incentive, because the marginal price of additional consumption is reduced. While SFV rates are being

[30] "Decoupling for Electric & Gas Utilities: Frequently Asked Questions (FAQ)" Grants & Research Department, National Association of Regulatory Utility Commissioners, at 5 (Sept. 2007) (emphasis added), https://www.maine.gov/mpuc/legislative/archive/2006legislation/DecouplingRpt-AttachC.pdf.

> considered to better reflect the utility's costs behind the rate, these rates do not encourage customers to change energy usage behavior or invest in efficiency technologies. Such customer disincentives persist even when SFV rates are applied to individual components of the bill, such as charges for distribution service.[31]

Q. CAN HIGH CUSTOMER CHARGES LEAD TO OTHER PROBLEMS?

A. Yes. In addition to disincentivizing energy conservation measures, increased customer charges also shift the rate burden within a customer class to lower-use customers. This results in equity concerns as lower-use customers have been shown to be consistently associated with lower income households in empirical research.

Q. HAVE YOU PREPARED ANY RESIDENTIAL TYPICAL BILL ANALYSES ASSOCIATED WITH THE COMPANY'S RATE DESIGN PROPOSALS?

A. Yes. Exhibit DED-14 illustrates various total distribution bill changes for residential customers of varying monthly usage levels. Three types of illustrative customers are identified in this analysis. Customer 1 represents a customer taking service under the standard residential service class who uses an average of 1,000 kWh per month. Customer 2 represents a smaller customer using an average of only 667 kWh per month, approximately a third less than the hypothetical system average. Customer 3 represents a larger customer using an average of 1,333 kWh per month, approximately a third more than the hypothetical system average. The

[31] Customer Incentives for Energy Efficiency Through Electric and Natural Gas Rate Design, National Action Plan for Energy Efficiency at 13-14, prepared by William Prindle, ICF International, Inc. (Sept. 2009) (emphasis added), https://www.epa.gov/sites/production/files/2015-08/documents/rate_design.pdf.

schedule shows that residential customers using close to the system average would see an increase of 4.57 percent in their bill. Those customers using greater than average use would incur a slightly smaller increase of 4.09 percent. Low-use residential customers would see their bill increase by 5.45 percent.

Q. WHAT ARE YOUR CUSTOMER CHARGE RECOMMENDATIONS AND CONCLUSIONS?

A. I recommend that the Commission reject the Company's proposed increase in customer charges. The Company's proposal would detrimentally impact the public policy goals of promoting energy efficiency. Likewise, it would burden low-use customers with a greater than average portion of any proposed increase in the case.

VII. CONCLUSIONS AND RECOMMENDATIONS

Q. WHAT CONCLUSIONS HAVE YOU DRAWN FROM YOUR REVIEW OF DESC'S APPLICATION AND FILINGS MADE IN THIS DOCKET?

A. Table 1 provides an illustrative comparison of the combined impact on class revenue allocations resulting from my recommended changes to the Company's CCOSS and revenue allocations, relative to the proposed revenue allocations included in the Company's filing.

Table 1: Comparison of Class Revenue Allocations

	Total Jurisdictional Electric	Residential Service	Small Commercial Service	Medium Commercial Service	Large Commercial Service	Lighting Service
DESC Proposed						
Revenue Increase ($ Thousands)	$ 178,233	$ 83,150	$ 35,387	$ 16,700	$ 41,122	$ 1,875
Percentage Increase	8.27%	8.24%	8.31%	8.78%	8.75%	3.13%
Alternative Proposed						
Revenue Increase ($ Thousands)	$ 178,702	$ 78,114	$ 32,977	$ 18,143	$ 44,832	$ 4,636
Percentage Increase	8.29%	7.74%	7.74%	9.53%	9.53%	7.74%

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS REGARDING THE COMPANY'S CLASS COST OF SERVICE STUDY.

A. I recommend that the Commission adopt an A&P cost allocation method to allocate costs associated with Company production plant facilities. An A&P cost allocation is a blended cost allocation method that recognizes the dual function of EGUs in serving both energy and demand needs of an electric system through baseload and peaking facilities. My analysis finds that a substantial portion of the Company's production plant in service is associated with EGUs that operate in a manner to serve baseload energy needs of the Company, including nuclear facilities such as the Company's V.C. Summer facility. The Company's proposed method, based fully on a CP measure of demand, classifies 100 percent of all costs associated with production plant facilities as being demand-related, and is therefore inconsistent with the operations of its generation fleet.

Q. DO YOU HAVE ANY OTHER RECOMMENDATIONS REGARDING FUTURE CLASS COST OF SERVICE STUDIES?

A. Yes. I recommend the Commission require the Company to gather monthly system coincident peak information on a class basis in the future. I further recommend that the Commission require the Company to file an alternative CCOSS allocating demand-related electric transmission plant on the basis of the results of a 12-CP measure of demand in its next base rate filing. The Company uses the same CP measure of demand used to allocate costs associated with production plant facilities to allocate costs associated with transmission plant facilities. This is inconsistent with the allocation method that is utilized by the FERC in deciding appropriate rates for transmission service as well as the methods that are commonly used by other state utility regulators.

Q. WHAT IS YOUR RECOMMENDATION REGARDING PROPOSED CLASS REVENUE ALLOCATIONS?

A. I recommend that the Commission adopt updated class revenue allocations reflecting the proposed alternative CCOSS results presented in Exhibit DED-9. In this alternative CCOSS, I find that medium and large general service customers are currently earning less than the system average rate of return. I therefore assigned a revenue increase to these two classes equal to 1.15 times the overall system average increase of 8.29 percent, or 9.51 percent. I then allocated the remaining required revenue increase equally to all other customer classes. This proposed alternative class revenue distribution reduces the proposed revenue increase to the residential service class from the Company's proposed $83.2 million to $78.1 million, or by approximately $5.0 million.

Q. WHAT ARE YOUR CUSTOMER CHARGE RECOMMENDATIONS AND CONCLUSIONS?

A. I recommend that the Commission reject the Company's proposed increase in customer charges. The Company's proposal would detrimentally impact the public policy goals of promoting energy efficiency. Likewise, it would burden low-use customers with a greater than average portion of any proposed increase in the case.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Table of Exhibits

Title	Exhibit
DESC Rates to State and Regional Averages (EEI)	CONFIDENTIAL Exhibit DED-1
DESC Rates to Neighboring IOUs (EEI)	CONFIDENTIAL Exhibit DED-2
DESC Rates Relative to State Averages (EEI)	CONFIDENTIAL Exhibit DED-3
Peer Comparison of Residential Base Revenues	Exhibit DED-4
Peer Comparison of Commercial Base Revenues	Exhibit DED-5
Peer Comparison of Industrial Base Revenues	Exhibit DED-6
Results of Company's Proposed Class Cost of Service Study	Exhibit DED-7
Analysis of Relative Company Electric Generation Units Classifications	Exhibit DED-8
Results of Alternative Class Cost of Service Study	Exhibit DED-9
Summary of Company's Proposed Revenue Distribution	Exhibit DED-10
Summary of Alternative Proposed Revenue Distribution	Exhibit DED-11
Summary of Current and Proposed Basic Facility Charges	Exhibit DED-12
Survey of Regional Customer Charges	Exhibit DED-13
Analysis of Residential Bill Impacts	Exhibit DED-14

DESC Rates to State and Regional Averages (EEI) -- Residential Rates

Source: Company's Response to Data Request DCA 1-13.

DESC Rates to State and Regional Averages (EEI) -- Commercial Rates

Average Rate
($ per kWh)

[redacted]

Winter 2018 | Summer 2018 | Winter 2019 | Summer 2019 | Winter 2020

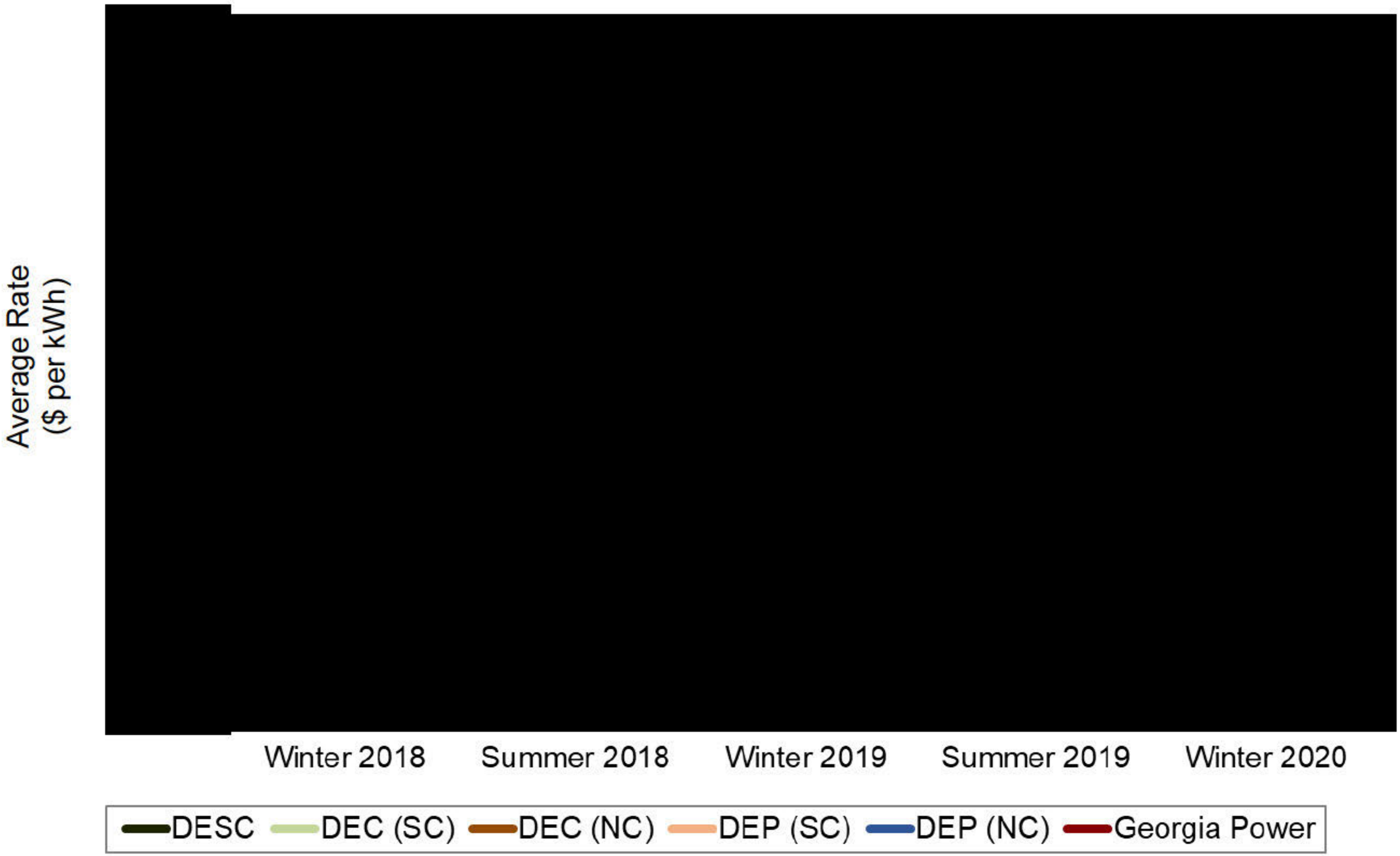
DESC | SC State Average | South Atlantic Region

Source: Company's Response to Data Request DCA 1-13.

DESC Rates to State and Regional Averages (EEI) -- Industrial Rates

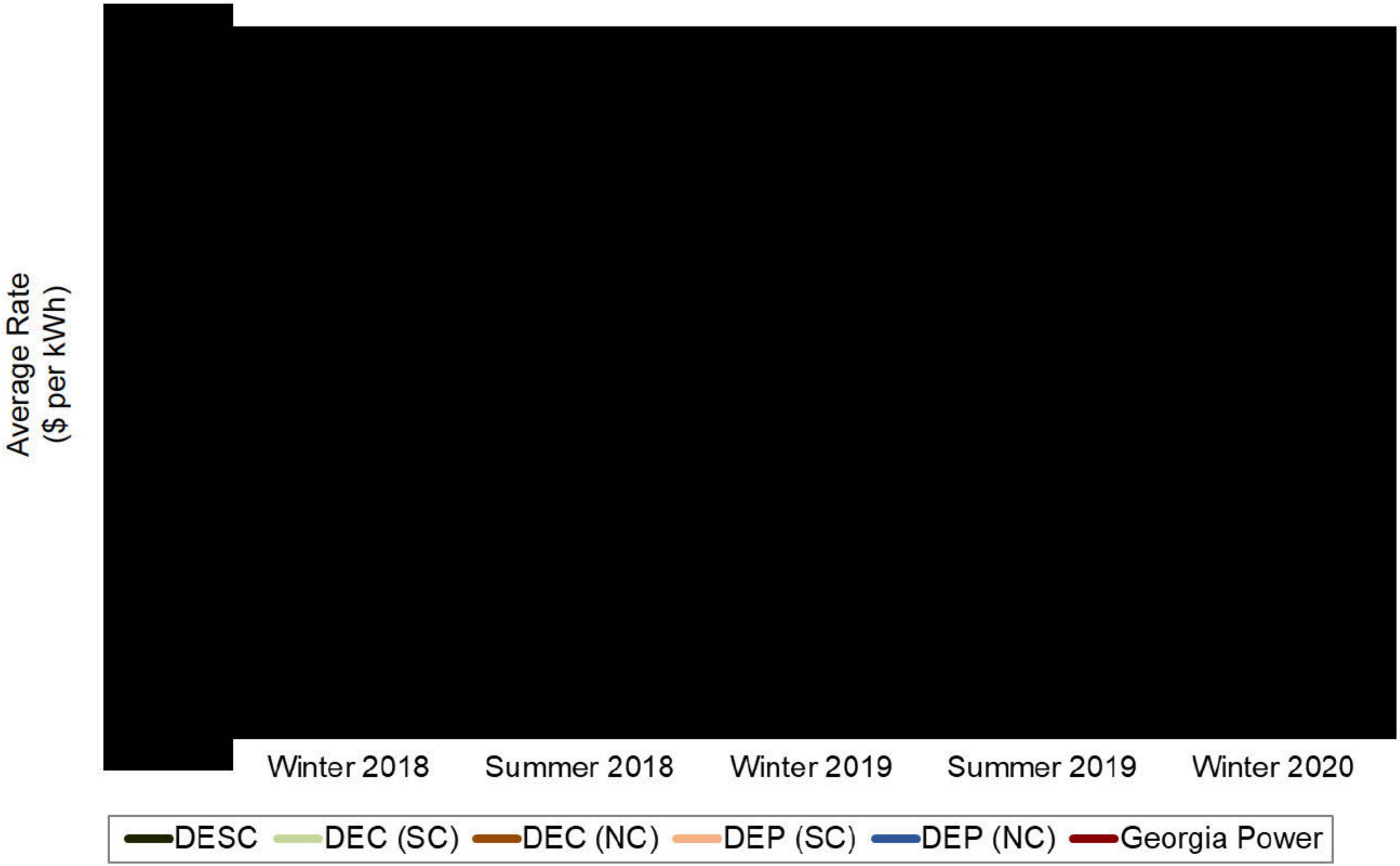
Source: Company's Response to Data Request DCA 1-13.

DESC Rates to Neighboring IOUs (EEI) -- Residential Rates



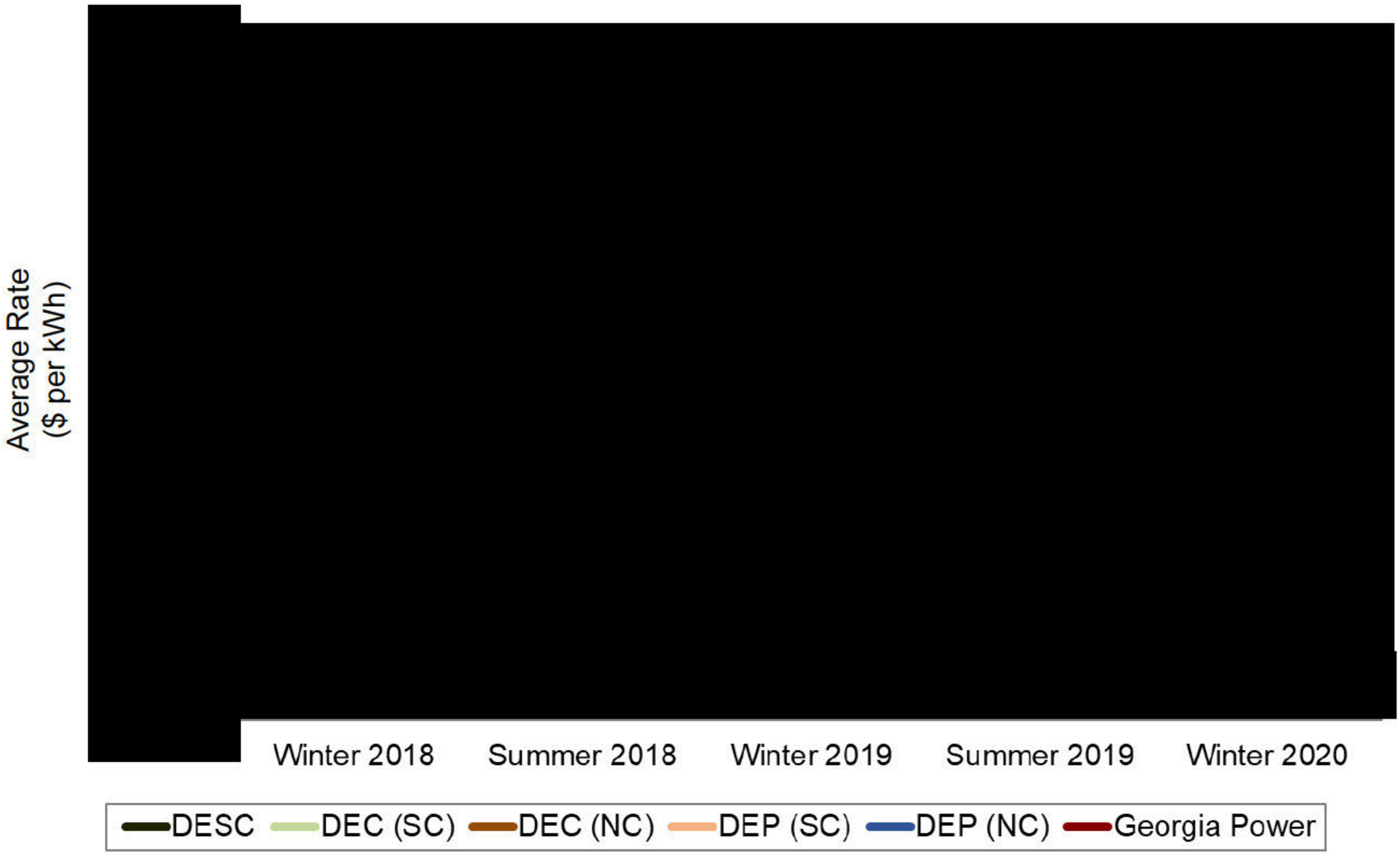
Source: Company's Response to Data Request DCA 1-13.

DESC Rates to Neighboring IOUs (EEI) -- Commercial Rates



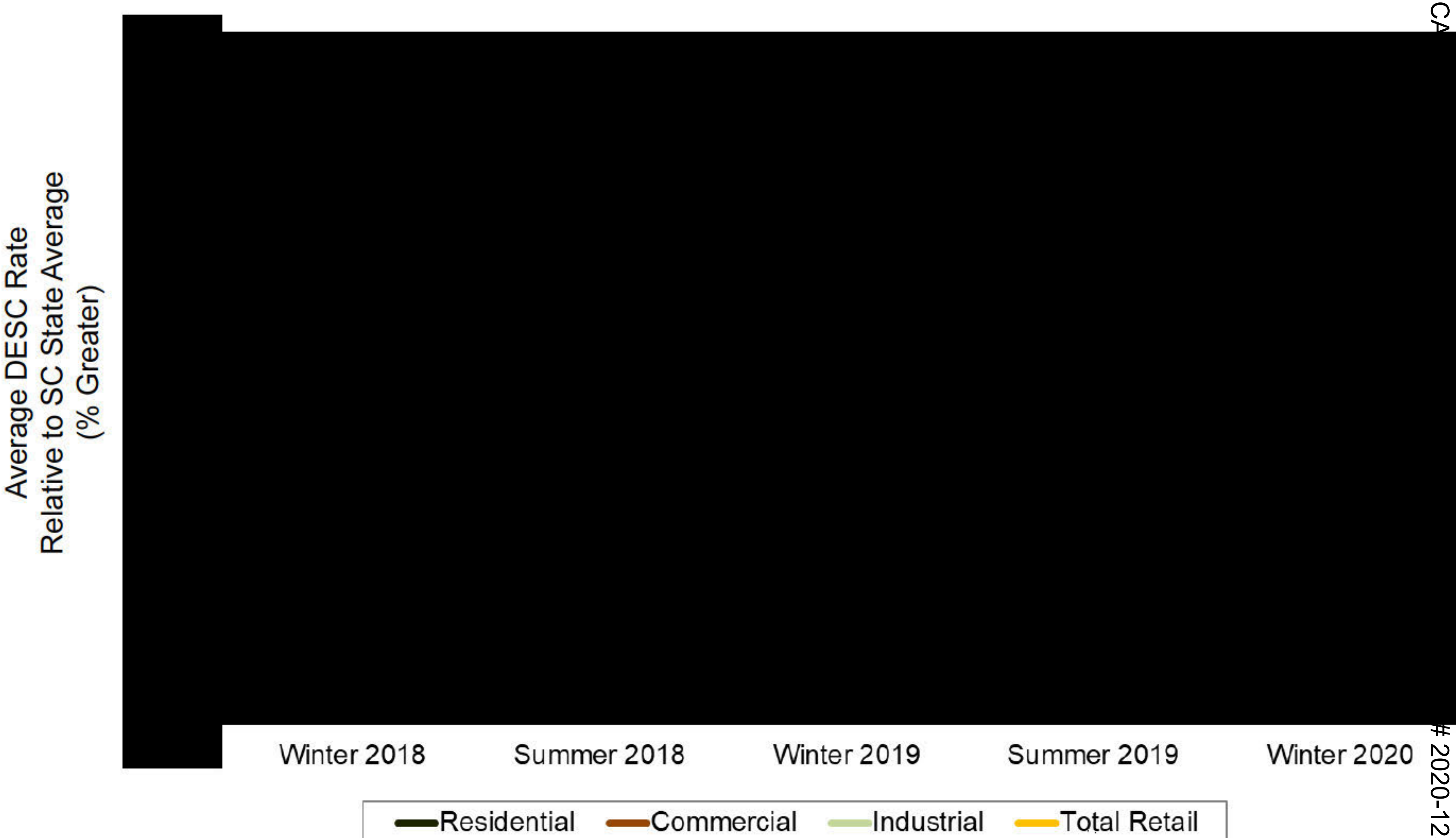
Source: Company's Response to Data Request DCA 1-13.

DESC Rates to Neighboring IOUs (EEI) -- Industrial Rates



Source: Company's Response to Data Request DCA 1-13.

DESC Rates Relative to State Averages (EEI)



Source: Company's Response to Data Request DCA 1-13.

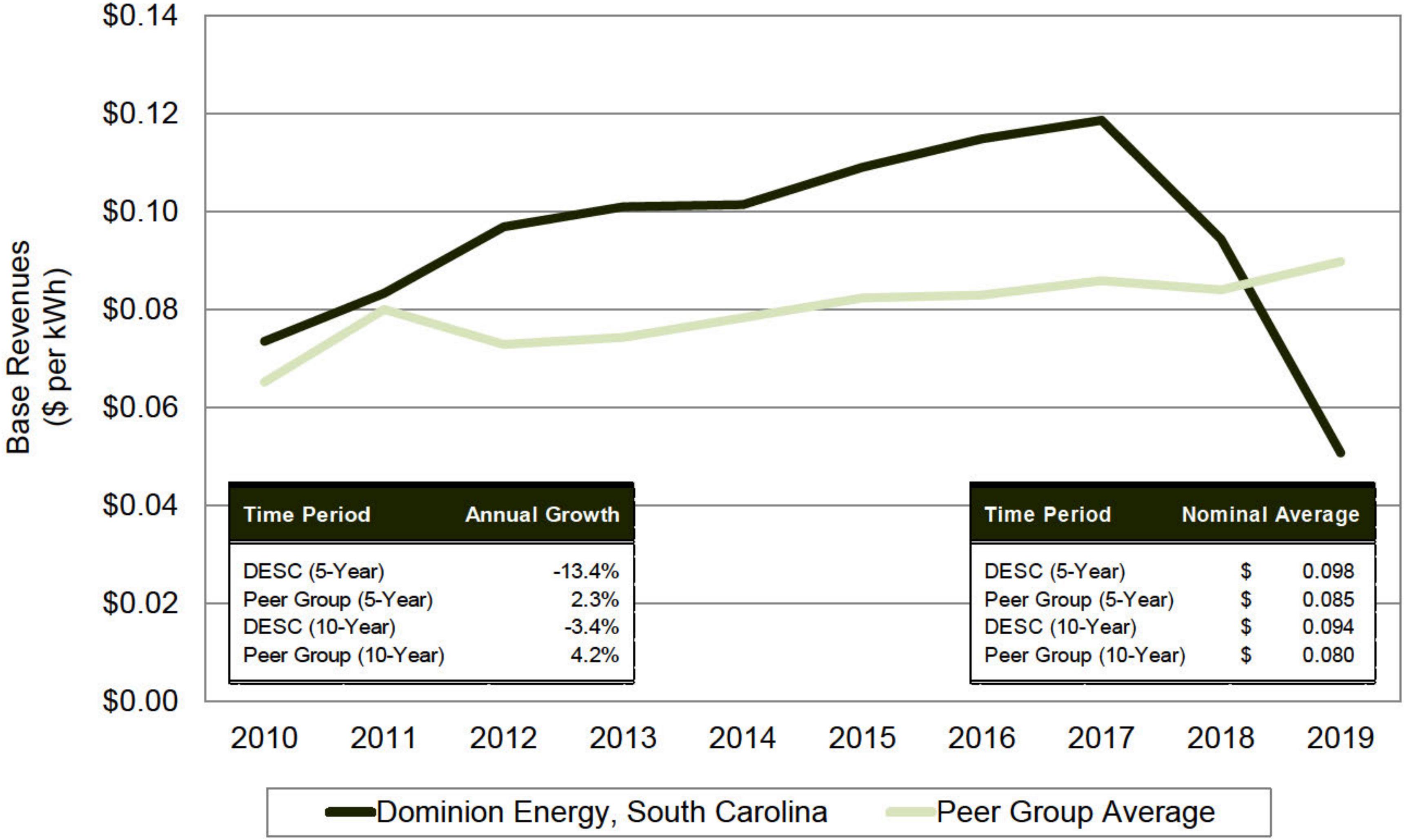
Peer Comparison of Residential Base Revenues

Company	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	($/kWh)									
Dominion Energy, South Carolina	**$ 0.074**	**$ 0.083**	**$ 0.097**	**$ 0.101**	**$ 0.101**	**$ 0.109**	**$ 0.115**	**$ 0.119**	**$ 0.094**	**$ 0.051**
Alabama Power Company	0.082	0.085	0.089	0.088	0.088	0.095	0.101	0.109	0.099	0.110
Dominion Virgina Power	0.067	0.070	0.076	0.075	0.075	0.079	0.087	0.090	0.084	0.091
Duke Energy Carolinas, LLC	0.065	0.066	0.077	0.076	0.080	0.084	0.084	0.080	0.082	0.085
Duke Energy Florida, LLC	0.069	0.066	0.073	0.067	0.077	0.081	0.070	0.075	0.082	0.092
Duke Energy Progress, LLC	0.069	0.070	0.071	0.074	0.071	0.076	0.079	0.079	0.085	0.089
Entergy Mississippi, Inc.	0.038	0.035	0.042	0.046	0.052	0.054	0.054	0.058	0.057	0.062
Florida Power & Light Company	0.055	0.060	0.063	0.069	0.073	0.072	0.073	0.081	0.080	0.082
Georgia Power Company	0.059	0.210	0.080	0.082	0.084	0.090	0.091	0.092	0.089	0.091
Gulf Power Company	0.070	0.074	0.081	0.077	0.086	0.095	0.094	0.100	0.088	0.096
Mississippi Power Company	0.074	0.076	0.079	0.095	0.102	0.102	0.101	0.105	0.102	0.111
Tampa Electric Company	0.072	0.068	0.070	0.070	0.074	0.077	0.077	0.077	0.078	0.080
Peer Group Average	**$ 0.065**	**$ 0.080**	**$ 0.073**	**$ 0.074**	**$ 0.078**	**$ 0.082**	**$ 0.083**	**$ 0.086**	**$ 0.084**	**$ 0.090**

Company	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	(Ranking)									
Dominion Energy, South Carolina	**11**	**10**	**12**	**12**	**11**	**12**	**12**	**12**	**10**	**1**
Alabama Power Company	12	11	11	10	10	9	10	11	11	11
Dominion Virgina Power	5	6	6	6	5	5	7	7	6	7
Duke Energy Carolinas, LLC	4	4	7	7	7	7	6	5	4	5
Duke Energy Florida, LLC	7	3	5	2	6	6	2	2	5	9
Duke Energy Progress, LLC	6	7	4	5	2	3	5	4	7	6
Entergy Mississippi, Inc.	1	1	1	1	1	1	1	1	1	2
Florida Power & Light Company	2	2	2	3	3	2	3	6	3	4
Georgia Power Company	3	12	9	9	8	8	8	8	9	8
Gulf Power Company	8	8	10	8	9	10	9	9	8	10
Mississippi Power Company	10	9	8	11	12	11	11	10	12	12
Tampa Electric Company	9	5	3	4	4	4	4	3	2	3

Note: In the 2019 FERC Form for Dominion Energy South Carolina, the Company noted that in January 2019, it "established a regulatory liability with a reduction to electric revenue of $1.007 billion for refunds and restitution to electric customers which is being credited to customers over approximately 11 years beginning in February 2019."
Source: Federal Energy Regulatory Commission, Annual Report of Major Electric Utilities ("FERC Form 1").

Peer Comparison of Residential Base Revenues



Time Period	Annual Growth
DESC (5-Year)	-13.4%
Peer Group (5-Year)	2.3%
DESC (10-Year)	-3.4%
Peer Group (10-Year)	4.2%

Time Period	Nominal Average	
DESC (5-Year)	$	0.098
Peer Group (5-Year)	$	0.085
DESC (10-Year)	$	0.094
Peer Group (10-Year)	$	0.080

Note: In the 2019 FERC Form for Dominion Energy South Carolina, the Company noted that in January 2019, it "established a regulatory liability with a reduction to electric revenue of $1.007 billion for refunds and restitution to electric customers which is being credited to customers over approximately 11 years beginning in February 2019."

Source: Federal Energy Regulatory Commission, Annual Report of Major Electric Utilities ("FERC Form 1").

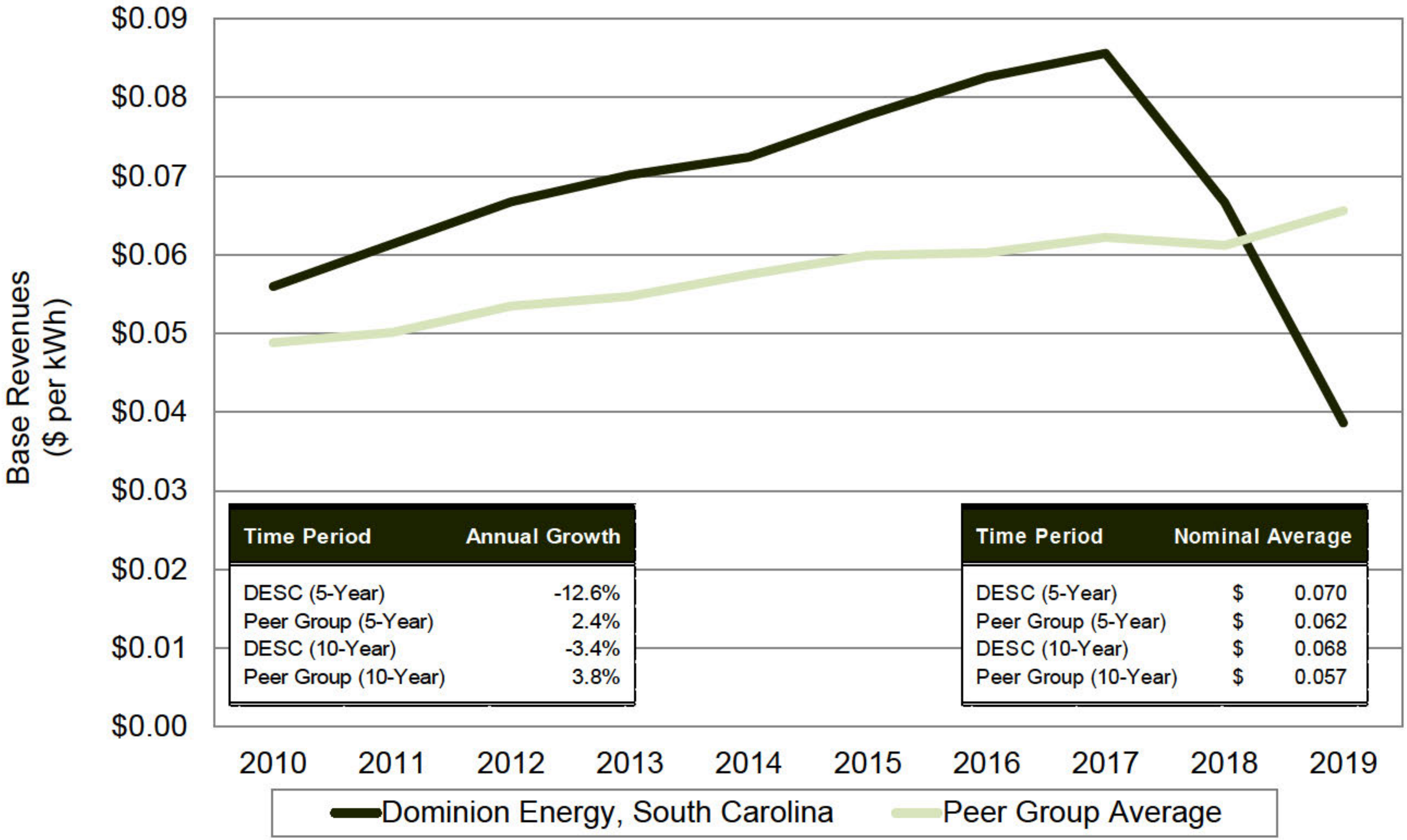
Peer Comparison of Commercial Base Revenues

Company	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	($/kWh)									
Dominion Energy, South Carolina	**$ 0.056**	**$ 0.061**	**$ 0.067**	**$ 0.070**	**$ 0.072**	**$ 0.078**	**$ 0.083**	**$ 0.086**	**$ 0.067**	**$ 0.039**
Alabama Power Company	0.074	0.076	0.079	0.078	0.079	0.084	0.090	0.097	0.087	0.096
Dominion Virgina Power	0.041	0.043	0.045	0.045	0.046	0.048	0.052	0.053	0.050	0.051
Duke Energy Carolinas, LLC	0.047	0.047	0.055	0.055	0.054	0.056	0.057	0.055	0.056	0.059
Duke Energy Florida, LLC	0.038	0.038	0.045	0.036	0.045	0.050	0.039	0.045	0.050	0.058
Duke Energy Progress, LLC	0.053	0.054	0.055	0.057	0.054	0.056	0.060	0.059	0.063	0.066
Entergy Mississippi, Inc.	0.035	0.032	0.038	0.043	0.049	0.049	0.049	0.051	0.052	0.057
Florida Power & Light Company	0.040	0.044	0.046	0.050	0.053	0.052	0.054	0.058	0.057	0.058
Georgia Power Company	0.044	0.054	0.056	0.058	0.061	0.063	0.064	0.065	0.063	0.065
Gulf Power Company	0.055	0.059	0.061	0.056	0.061	0.069	0.066	0.070	0.060	0.067
Mississippi Power Company	0.053	0.054	0.054	0.068	0.075	0.074	0.073	0.076	0.075	0.082
Tampa Electric Company	0.056	0.053	0.055	0.055	0.056	0.058	0.059	0.057	0.058	0.061
Peer Group Average	**$ 0.049**	**$ 0.050**	**$ 0.053**	**$ 0.055**	**$ 0.057**	**$ 0.060**	**$ 0.060**	**$ 0.062**	**$ 0.061**	**$ 0.066**

Company	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	(Ranking)									
Dominion Energy, South Carolina	**10**	**11**	**11**	**11**	**10**	**11**	**11**	**11**	**10**	**1**
Alabama Power Company	12	12	12	12	12	12	12	12	12	12
Dominion Virgina Power	4	3	2	3	2	1	3	3	2	2
Duke Energy Carolinas, LLC	6	5	6	5	6	6	5	4	4	6
Duke Energy Florida, LLC	2	2	3	1	1	3	1	1	1	4
Duke Energy Progress, LLC	8	8	7	8	5	5	7	7	9	9
Entergy Mississippi, Inc.	1	1	1	2	3	2	2	2	3	3
Florida Power & Light Company	3	4	4	4	4	4	4	6	5	5
Georgia Power Company	5	9	9	9	8	8	8	8	8	8
Gulf Power Company	9	10	10	7	9	9	9	9	7	10
Mississippi Power Company	7	7	5	10	11	10	10	10	11	11
Tampa Electric Company	11	6	8	6	7	7	6	5	6	7

Note: In the 2019 FERC Form for Dominion Energy South Carolina, the Company noted that in January 2019, it "established a regulatory liability with a reduction to electric revenue of $1.007 billion for refunds and restitution to electric customers which is being credited to customers over approximately 11 years beginning in February 2019."
Source: Federal Energy Regulatory Commission, Annual Report of Major Electric Utilities (“FERC Form 1”).

Peer Comparison of Commercial Base Revenues



Time Period	Annual Growth
DESC (5-Year)	-12.6%
Peer Group (5-Year)	2.4%
DESC (10-Year)	-3.4%
Peer Group (10-Year)	3.8%

Time Period	Nominal Average	
DESC (5-Year)	$	0.070
Peer Group (5-Year)	$	0.062
DESC (10-Year)	$	0.068
Peer Group (10-Year)	$	0.057

Note: In the 2019 FERC Form for Dominion Energy South Carolina, the Company noted that in January 2019, it "established a regulatory liability with a reduction to electric revenue of $1.007 billion for refunds and restitution to electric customers which is being credited to customers over approximately 11 years beginning in February 2019."
Source: Federal Energy Regulatory Commission, Annual Report of Major Electric Utilities ("FERC Form 1").

Witness: Dismukes
Docket No. 2020-125-E
Exhibit DED-6
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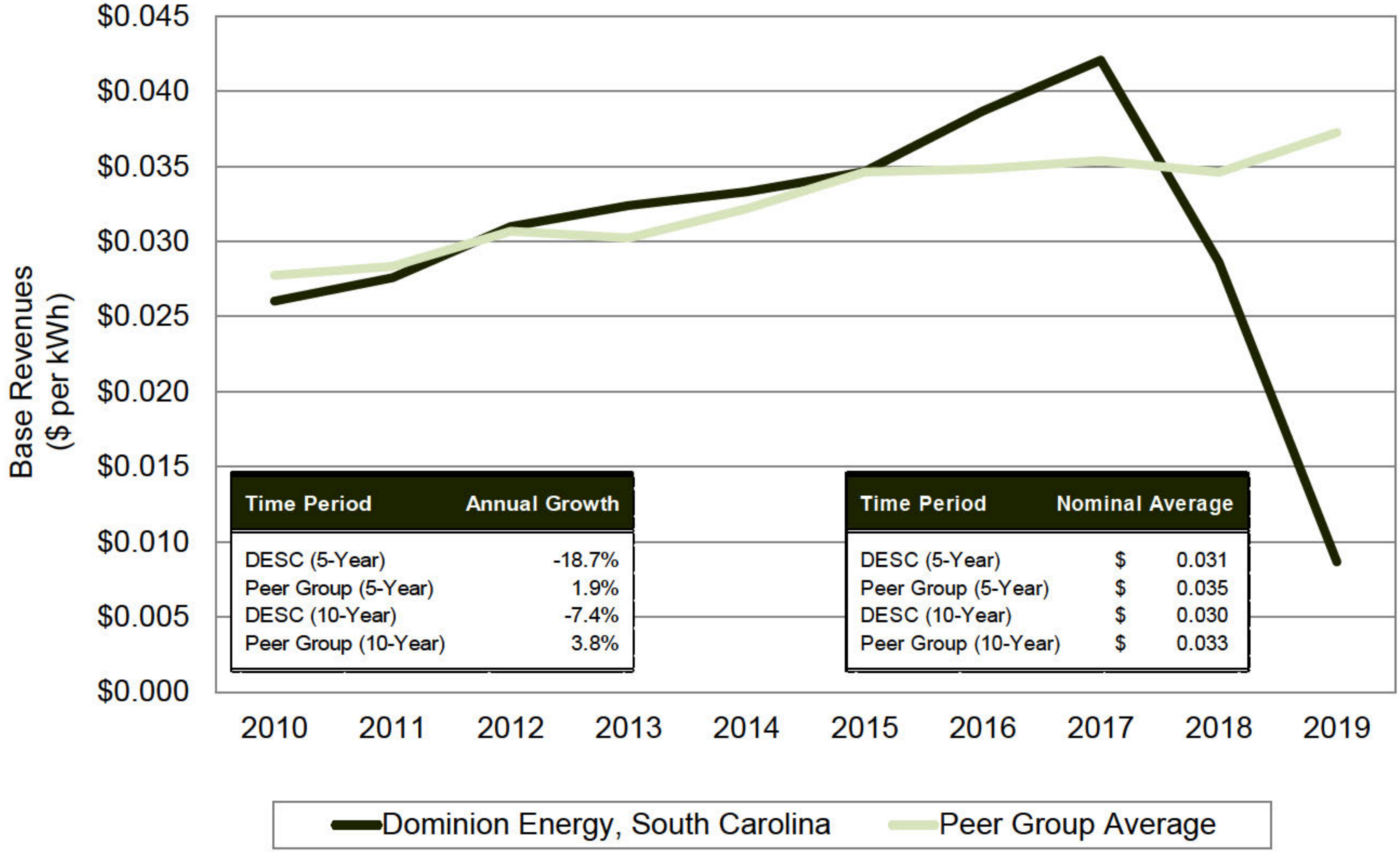
Peer Comparison of Industrial Base Revenues

Company	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	($/kWh)									
Dominion Energy, South Carolina	**$ 0.026**	**$ 0.028**	**$ 0.031**	**$ 0.032**	**$ 0.033**	**$ 0.035**	**$ 0.039**	**$ 0.042**	**$ 0.029**	**$ 0.009**
Alabama Power Company	0.030	0.031	0.033	0.032	0.032	0.035	0.038	0.040	0.035	0.039
Dominion Virgina Power	0.024	0.024	0.027	0.027	0.028	0.030	0.035	0.035	0.033	0.036
Duke Energy Carolinas, LLC	0.027	0.026	0.033	0.032	0.033	0.037	0.035	0.033	0.035	0.036
Duke Energy Florida, LLC	0.026	0.026	0.033	0.024	0.031	0.037	0.028	0.032	0.034	0.042
Duke Energy Progress, LLC	0.034	0.034	0.033	0.033	0.031	0.032	0.034	0.034	0.037	0.035
Entergy Mississippi, Inc.	0.018	0.014	0.019	0.022	0.025	0.026	0.027	0.026	0.026	0.030
Florida Power & Light Company	0.022	0.028	0.028	0.030	0.032	0.031	0.033	0.037	0.035	0.036
Georgia Power Company	0.018	0.022	0.022	0.022	0.025	0.024	0.024	0.025	0.026	0.029
Gulf Power Company	0.039	0.042	0.042	0.034	0.038	0.045	0.043	0.045	0.036	0.039
Mississippi Power Company	0.021	0.022	0.024	0.032	0.036	0.036	0.038	0.039	0.038	0.040
Tampa Electric Company	0.045	0.043	0.045	0.045	0.044	0.047	0.048	0.044	0.045	0.048
Peer Group Average	**$ 0.028**	**$ 0.028**	**$ 0.031**	**$ 0.030**	**$ 0.032**	**$ 0.035**	**$ 0.035**	**$ 0.035**	**$ 0.035**	**$ 0.037**

Company	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
	(Ranking)									
Dominion Energy, South Carolina	**6**	**8**	**6**	**9**	**9**	**6**	**10**	**10**	**3**	[illegible]
Alabama Power Company	9	9	7	6	7	7	8	9	7	8
Dominion Virgina Power	5	4	4	4	3	3	6	6	4	[illegible]
Duke Energy Carolinas, LLC	8	6	9	8	8	9	7	4	6	5
Duke Energy Florida, LLC	7	5	8	3	5	10	3	3	5	11
Duke Energy Progress, LLC	10	10	10	10	4	5	5	5	10	4
Entergy Mississippi, Inc.	2	1	1	1	1	2	2	2	1	3
Florida Power & Light Company	4	7	5	5	6	4	4	7	8	6
Georgia Power Company	1	2	2	2	2	1	1	1	2	2
Gulf Power Company	11	11	11	11	11	11	11	12	9	9
Mississippi Power Company	3	3	3	7	10	8	9	8	11	10
Tampa Electric Company	12	12	12	12	12	12	12	11	12	12

Note: In the 2019 FERC Form for Dominion Energy South Carolina, the Company noted that in January 2019, it "established a regulatory liability with a reduction to electric revenue of $1.007 billion for refunds and restitution to electric customers which is being credited to customers over approximately 11 years beginning in February 2019."
Source: Federal Energy Regulatory Commission, Annual Report of Major Electric Utilities ("FERC Form 1").

Peer Comparison of Industrial Base Revenues



Time Period	Annual Growth
DESC (5-Year)	-18.7%
Peer Group (5-Year)	1.9%
DESC (10-Year)	-7.4%
Peer Group (10-Year)	3.8%

Time Period	Nominal Average	
DESC (5-Year)	$	0.031
Peer Group (5-Year)	$	0.035
DESC (10-Year)	$	0.030
Peer Group (10-Year)	$	0.033

Note: In the 2019 FERC Form for Dominion Energy South Carolina, the Company noted that in January 2019, it "established a regulatory liability with a reduction to electric revenue of $1.007 billion for refunds and restitution to electric customers which is being credited to customers over approximately 11 years beginning in February 2019."
Source: Federal Energy Regulatory Commission, Annual Report of Major Electric Utilities ("FERC Form 1").

Results of Company's Proposed Class Cost of Service Study

Account Description	Total Electric	Total Jurisdictional Electric	Residential Service	Small Commercial Service	Medium Commercial Service	Large Commercial Service	Lighting Service
		($ Thousands)					
Rate Base							
Total Electric Plant in Service	$ 11,105,339	$10,878,045	$5,435,273	$ 2,176,198	$ 945,761	$ 1,885,513	$ 435,300
Less: Depreciation Reserve	4,765,053	4,659,205	2,316,831	934,279	412,828	840,095	155,170
Total Net Electric Plant in Service	$ 6,340,286	$ 6,218,840	$3,118,441	$ 1,241,919	$ 532,933	$ 1,045,418	$ 280,130
Rate Base Additions							
Plus: Construction Work in Progres (CWIP)	$ 565,129	$ 551,793	$ 272,209	$ 110,805	$ 49,406	$ 103,894	$ 15,480
Plus: Working Capital	(22,782)	(24,159)	(18,705)	(8,742)	2,816	4,911	(4,438)
Plus: Materials and Supplies	410,634	397,208	171,914	73,627	38,799	104,629	8,238
Rate Base Reductions							
Less: Deferred Credits	480,105	471,218	239,323	93,607	39,691	75,479	23,117
Less: Accumulated Deferred Income Taxes (ADIT)	942,271	923,814	463,019	184,573	79,564	156,433	40,224
Total Rate Base	**$ 5,870,891**	**$ 5,748,651**	**$2,841,517**	**$ 1,139,428**	**$ 504,697**	**$ 1,026,940**	**$ 236,069**
Operating Income							
Total Electric Operating Revenues	**$ 2,118,108**	**$ 2,067,371**	**$ 973,668**	**$ 418,255**	**$ 186,090**	**$ 429,017**	**$ 60,340**
Electric Operating Expenses							
Fuel Expense	$ 590,342	$ 567,776	$ 222,967	$ 99,582	$ 58,380	$ 179,040	$ 7,808
Other Operating Expenses	593,242	579,519	301,071	113,097	48,757	104,719	11,874
Depreciation & Amortization Expense	308,926	298,648	149,177	59,691	25,975	51,814	11,991
Taxes Other than Income	238,120	233,015	116,059	46,624	20,442	40,813	9,077
Income Taxes	34,885	34,222	14,157	12,794	3,328	5,262	(1,318)
Total Electric Operating Expenses	**$ 1,765,515**	**$ 1,713,180**	**$ 803,431**	**$ 331,788**	**$ 156,882**	**$ 381,648**	**$ 39,431**
Operating Return	**$ 352,593**	**$ 354,191**	**$ 170,237**	**$ 86,467**	**$ 29,208**	**$ 47,369**	**$ 20,909**
Plus: Customer Growth	1,151	1,151	969	261	(153)	126	(52)
Less: Interest on Customer Deposits	1,385	1,385	880	248	71	145	42
Total Operating Income	**$ 352,359**	**$ 353,957**	**$ 170,326**	**$ 86,481**	**$ 28,984**	**$ 47,350**	**$ 20,815**
Rate of Return on Rate Base ("ROR")	**6.00%**	**6.16%**	**5.99%**	**7.59%**	**5.74%**	**4.61%**	**8.82%**
Relative Rate of Return ("RROR")	**1.00**	**1.03**	**1.00**	**1.26**	**0.96**	**0.77**	**1.47**

Source: Direct Testimony of Kevin R. Kochems, Exhibit KRK-1.

Results of Company's Proposed Class Cost of Service Study

Account Description	Total Electric	Total Jurisdictional Electric	Residential Service	Small Commercial Service	Medium Commercial Service	Large Commercial Service	Lighting Service
		($ Thousands)					
Required Income Under Company's Proposed ROR							
Total Rate Base	$ 5,870,891	$ 5,748,651	$ 2,841,517	$ 1,139,428	$ 504,697	$ 1,026,940	$236,069
Proposed Rate of Return	8.48%	8.48%	8.48%	8.48%	8.48%	8.48%	8.48%
Required Operating Income at 8.48 ROR	$ 497,649	$ 487,287	$ 240,862	$ 96,584	$ 42,781	$ 87,049	$ 20,011
Electric Operating Expenses							
Current Total Electric Operating Expenses	$ 1,765,515	$ 1,713,180	$ 803,431	$ 331,788	$ 156,882	$ 381,648	$ 39,431
Total Electric Operating Expenses	**$ 1,765,515**	**$ 1,713,180**	**$ 803,431**	**$ 331,788**	**$ 156,882**	**$ 381,648**	**$ 39,431**
Total Cost of Service	**$ 2,263,163**	**$ 2,200,467**	**$ 1,044,294**	**$ 428,372**	**$ 199,663**	**$ 468,697**	**$ 59,442**
Net Operating Income (Present Rates)							
Total Rate Revenue	$ 2,118,108	$ 2,067,371	$ 973,668	$ 418,255	$ 186,090	$ 429,017	$ 60,340
Plus: Customer Growth	1,151	1,151	969	261	(153)	126	(52)
Less: Interest on Customer Deposits	1,385	1,385	880	248	71	145	42
Total Electric Operating Revenues	**$ 2,117,874**	**$ 2,067,137**	**$ 973,758**	**$ 418,268**	**$ 185,866**	**$ 428,998**	**$ 60,246**
Income Deficiency	**$ 145,289**	**$ 133,330**	**$ 70,536**	**$ 10,104**	**$ 13,797**	**$ 39,699**	**$ (804)**
Revenue Gross Factor	1.33914	1.33914	1.33914	1.33914	1.33914	1.33914	1.33914
Revenue Deficiency	**$ 194,562**	**$ 178,547**	**$ 94,457**	**$ 13,530**	**$ 18,476**	**$ 53,162**	**$ (1,077)**
Proposed Rate Increase (Percent)		**8.64%**	**9.70%**	**3.23%**	**9.94%**	**12.39%**	**-1.79%**
Relative Proposed Rate Increase		**1.00**	**1.12**	**0.37**	**1.15**	**1.43**	**-0.21**

Source: Direct Testimony of Kevin R. Kochems, Exhibit KRK-1.

Witness: Dismukes
Docket No. 2020-125-E
Exhibit DED-8

Analysis of Relative Company Electric Generation Units Classifications

Station Name	Plant Type	Nameplate Capacity (MW)	2019 Net Generation (MWh)	2019 Capacity Factor	Allocation Energy	Allocation Demand	Plant in Service Energy	Plant in Service Demand	Plant in Service Total
							---------- ($ Millions) ----------		
V.C. Summer	Nuclear	686.4	5,502,476	91.5%	91.5%	8.5%	$ 1,216.6	$ 112.8	$ 1,329.[illegible]
Wateree	Coal	771.8	2,061,246	30.5%	30.5%	69.5%	283.3	645.9	929.[illegible]
Cope	Coal	417.4	1,851,609	50.6%	50.6%	49.4%	282.2	275.0	557.[illegible]
Jasper	Gas-CC	1,001.7	5,184,176	59.1%	59.1%	40.9%	302.4	209.4	511.8
Saluda	Hydro-Conventional	207.3	142,447	7.8%	0.0%	100.0%	-	390.7	390.7
Urquhart	Gas-CC	547.8	1,709,368	35.6%	35.6%	64.4%	94.4	170.6	264.[illegible]
Columbia Energy Center	Gas-CC	668.5	3,251,098	55.5%	55.5%	44.5%	146.7	117.6	264.3
Fairfield	Hydro-Pumped Storage	586.0	-184,337	-3.6%	0.0%	100.0%	-	232.8	232.[illegible]
McMeekin	Gas-Steam	293.8	752,842	29.3%	29.3%	70.7%	58.4	141.3	199.7
Urquhart	Gas-Steam	100.0	45,623	5.2%	0.0%	100.0%	-	143.0	143.0
Hagood	Gas-CT	177.2	13,230	0.9%	0.0%	100.0%	-	50.8	50.8
Urquhart	Gas-CT	111.2	11,032	1.1%	0.0%	100.0%	-	34.6	34.6
Stevens Creek	Hydro-Run of the River	17.3	82,955	54.8%	54.8%	45.2%	8.8	7.3	16.1
Parr	Hydro-Run of the River	14.9	44,878	34.4%	34.4%	65.6%	4.6	8.8	13.4
Parr	Gas-CT	83.6	2,386	0.3%	0.0%	100.0%	-	12.5	12.5
Williams	Gas-CT	54.0	311	0.1%	0.0%	100.0%	-	7.9	7.9
Coit	Gas-CT	39.3	316	0.1%	0.0%	100.0%	-	6.5	6.5
Hardeeville	Gas-CT	16.3	0	0.0%	0.0%	100.0%	-	3.6	3.6
Subtotals:							**$ 2,397.4**	**$ 2,571.1**	**$ 4,968.5**
					Production Plant Classification:		**48.3%**	**51.7%**	**100.0%**

Source: Federal Energy Regulatory Commission, Annual Report of Major Electric Utilities ("FERC Form 1").

Results of Alternative Class Cost of Service Study

Account Description	Total Electric	Total Jurisdictional Electric	Residential Service	Small Commercial Service	Medium Commercial Service	Large Commercial Service	Lighting Service
		($ Thousands)					
Rate Base							
Total Electric Plant in Service	$ 11,105,339	$10,850,441	$5,150,084	$ 2,086,377	$ 963,449	$ 2,173,467	$ 477,063
Less: Depreciation Reserve	4,765,053	4,644,308	2,162,950	885,852	422,356	995,450	177,700
Total Net Electric Plant in Service	$ 6,340,286	$ 6,206,133	$2,987,135	$ 1,200,525	$ 541,094	$ 1,178,018	$ 299,363
Rate Base Additions							
Plus: Construction Work in Progres (CWIP)	$ 565,129	$ 550,201	$ 255,790	$ 105,652	$ 50,417	$ 120,475	$ 17,866
Plus: Working Capital	(22,782)	(24,142)	(18,668)	(8,728)	2,817	4,874	(4,436)
Plus: Materials and Supplies	410,634	396,764	167,232	72,154	39,101	109,360	8,917
Rate Base Reductions							
Less: Deferred Credits	480,105	470,477	229,426	90,514	40,287	85,598	24,652
Less: Accumulated Deferred Income Taxes (ADIT)	942,271	921,696	441,138	177,679	80,923	178,529	43,428
Total Rate Base	**$ 5,870,891**	**$ 5,736,783**	**$2,720,925**	**$ 1,101,410**	**$ 512,219**	**$ 1,148,599**	**$ 253,629**
Operating Income							
Total Electric Operating Revenues	**$ 2,118,108**	**$ 2,067,321**	**$ 972,882**	**$ 417,875**	**$ 186,164**	**$ 429,941**	**$ 60,459**
Electric Operating Expenses							
Fuel Expense	$ 590,339	$ 567,261	$ 222,366	$ 99,368	$ 58,382	$ 179,300	$ 7,845
Other Operating Expenses	593,245	578,072	287,853	108,938	49,550	117,940	13,791
Depreciation & Amortization Expense	308,926	301,760	143,358	58,057	26,823	60,389	13,133
Taxes Other than Income	238,120	232,417	110,653	44,948	20,747	46,213	9,856
Income Taxes	34,885	34,975	20,047	14,631	2,997	(593)	(2,107)
Total Electric Operating Expenses	**$ 1,765,515**	**$ 1,714,486**	**$ 784,277**	**$ 325,943**	**$ 158,498**	**$ 403,249**	**$ 42,518**
Operating Return	**$ 352,593**	**$ 352,836**	**$ 188,605**	**$ 91,932**	**$ 27,666**	**$ 26,691**	**$ 17,941**
Plus: Customer Growth	1,151	1,151	969	261	(153)	126	(52)
Less: Interest on Customer Deposits	1,385	1,385	880	248	71	145	42
Total Operating Income	**$ 352,359**	**$ 352,602**	**$ 188,695**	**$ 91,946**	**$ 27,442**	**$ 26,672**	**$ 17,847**
Rate of Return on Rate Base ("ROR")	**6.00%**	**6.15%**	**6.93%**	**8.35%**	**5.36%**	**2.32%**	**7.04%**
Relative Rate of Return ("RROR")	**1.00**	**1.02**	**1.16**	**1.39**	**0.89**	**0.39**	**1.17**

Results of Alternative Class Cost of Service Study

Account Description	Total Electric	Total Jurisdictional Electric	Residential Service	Small Commercial Service	Medium Commercial Service	Large Commercial Service	Lighting Service
		($ Thousands)					
Required Income Under Company's Proposed ROR							
Total Rate Base	$ 5,870,891	$ 5,736,783	$ 2,720,925	$ 1,101,410	$ 512,219	$ 1,148,599	$253,629
Proposed Rate of Return	8.48%	8.48%	8.48%	8.48%	8.48%	8.48%	8.48%
Required Operating Income at 8.48 ROR	$ 497,649	$ 486,281	$ 230,640	$ 93,362	$ 43,418	$ 97,362	$ 21,499
Electric Operating Expenses							
Current Total Electric Operating Expenses	$ 1,765,515	$ 1,714,486	$ 784,277	$ 325,943	$ 158,498	$ 403,249	$ 42,518
Total Electric Operating Expenses	**$ 1,765,515**	**$ 1,714,486**	**$ 784,277**	**$ 325,943**	**$ 158,498**	**$ 403,249**	**$ 42,518**
Total Cost of Service	**$ 2,263,163**	**$ 2,200,767**	**$ 1,014,917**	**$ 419,304**	**$ 201,917**	**$ 500,611**	**$ 64,017**
Net Operating Income (Present Rates)							
Total Rate Revenue	$ 2,118,108	$ 2,067,321	$ 972,882	$ 417,875	$ 186,164	$ 429,941	$ 60,459
Plus: Customer Growth	1,151	1,151	969	261	(153)	126	(52)
Less: Interest on Customer Deposits	1,385	1,385	880	248	71	145	42
Total Electric Operating Revenues	**$ 2,117,874**	**$ 2,067,087**	**$ 972,972**	**$ 417,888**	**$ 185,940**	**$ 429,922**	**$ 60,365**
Income Deficiency	**$ 145,289**	**$ 133,679**	**$ 41,946**	**$ 1,416**	**$ 15,976**	**$ 70,689**	**$ 3,652**
Revenue Gross Factor	1.33914	1.33914	1.33914	1.33914	1.33914	1.33914	1.33914
Revenue Deficiency	**$ 194,562**	**$ 179,015**	**$ 56,171**	**$ 1,896**	**$ 21,395**	**$ 94,663**	**$ 4,890**
Proposed Rate Increase (Percent)		**8.66%**	**5.77%**	**0.45%**	**11.51%**	**22.02%**	**8.10%**
Relative Proposed Rate Increase		**1.00**	**0.67**	**0.05**	**1.33**	**2.54**	**0.94**

Witness: Dismukes
Docket No. 2020-125-E
Exhibit DED-10

Summary of Company's Proposed Revenue Distribution

	Total Jurisdictional Electric	Residential Service	Small Commercial Service	Medium Commercial Service	Large Commercial Service	Lighting Service
		---------- ($ Thousands) ----------				
Cost of Service Results						
COS Operating Revenue	$ 2,067,371	$ 973,668	$ 418,255	$ 186,090	$ 429,017	$ 60,340
Operating Expenses	$ 1,713,180	$ 803,431	$ 331,788	$ 156,882	$ 381,648	$ 39,431
Plus: Customer Growth	1,151	969	261	(153)	126	(52)
Less: Interest on Customer Deposits	1,385	880	248	71	145	42
Total Operating Income	$ 353,957	$ 170,326	$ 86,481	$ 28,984	$ 47,350	$ 20,815
Rate Base	$ 5,748,651	$ 2,841,517	$ 1,139,428	$ 504,697	$ 1,026,940	$ 236,069
Rate of Return	**6.16%**	**5.99%**	**7.59%**	**5.74%**	**4.61%**	**8.82%**
Relative Rate of Return	**1.00**	**0.97**	**1.23**	**0.93**	**0.75**	**1.43**
Revenue Increse						
Proposed ROE	8.47%					
Required Income	$ 487,053					
Income Deficiency	$ 133,096					
Revenue Conversion Factor	1.33914					
Revenue Deficiency	$ 178,234					
Current Annualized Revenues	$ 2,155,389	$ 1,009,033	$ 425,982	$ 190,285	$ 470,207	$ 59,882
Proposed System ROR						
Operating Income from COS	$ 353,957	$ 170,326	$ 86,481	$ 28,984	$ 47,350	$ 20,815
Operating Income at System ROR	487,053	240,747	96,538	42,760	87,007	20,001
Incremental Income at System ROR	$ 133,096	$ 70,420	$ 10,057	$ 13,776	$ 39,657	$ (814)
Revenue Conversion Factor	1.33914	1.33914	1.33914	1.33914	1.33914	1.33914
Incremental Revenue Requirement at System ROR	$ 178,234	$ 94,302	$ 13,468	$ 18,448	$ 53,106	$ (1,090)
Percent Increase at System ROR	8.27%	9.35%	3.16%	9.69%	11.29%	-1.82%
Proposed Increase						
Percentage Class Increase	8.27%	8.24%	8.31%	8.78%	8.75%	3.13%
Total Proposed Revenue Increase	**$ 178,233**	**$ 83,150**	**$ 35,387**	**$ 16,700**	**$ 41,122**	**$ 1,875**
Class Revenue Increase Allocation						
Current Annualized Revenues	$ 2,155,389	$ 1,009,033	$ 425,982	$ 190,285	$ 470,207	$ 59,882
Proposed Revenue Increase	$ 178,233	$ 83,150	$ 35,387	$ 16,700	$ 41,122	$ 1,875
Proposed Revenues	$ 2,333,623	$ 1,092,183	$ 461,369	$ 206,985	$ 511,329	$ 61,757
Proposed Revenue Increase	**8.27%**	**8.24%**	**8.31%**	**8.78%**	**8.75%**	**3.13%**
Relative Revenue Increase	**1.00**	**1.00**	**1.00**	**1.06**	**1.06**	**0.38**

Source: Direct Testimony of Kevin R. Kochems, Exhibits KRK-1 and KRK-2; and Direct Testimony of Allen R. Rooks, Exhibit AWR-1.

Summary of Alternative Proposed Revenue Distribution

Witness: Dismukes
Docket No. 2020-125-E
Exhibit DED-11

	Total Jurisdictional Electric	Residential Service	Small Commercial Service	Medium Commercial Service	Large Commercial Service	Lighting Service
		($ Thousands)				
Cost of Service Results						
COS Operating Revenue	$ 2,067,321	$ 972,882	$ 417,875	$ 186,164	$ 429,941	$ 60,459
Operating Expenses	$ 1,714,486	$ 784,277	$ 325,943	$ 158,498	$ 403,249	$ 42,518
Plus: Customer Growth	1,151	969	261	(153)	126	(52)
Less: Interest on Customer Deposits	1,385	880	248	71	145	42
Total Operating Income	$ 352,602	$ 188,695	$ 91,946	$ 27,442	$ 26,672	$ 17,847
Rate Base	$ 5,736,783	$ 2,720,925	$ 1,101,410	$ 512,219	$ 1,148,599	$ 253,629
Rate of Return	**6.15%**	**6.93%**	**8.35%**	**5.36%**	**2.32%**	**7.04%**
Relative Rate of Return	**1.00**	**1.13**	**1.36**	**0.87**	**0.38**	**1.14**
Revenue Increse						
Proposed ROE	8.47%					
Required Income	$ 486,047					
Income Deficiency	$ 133,446					
Revenue Conversion Factor	1.33914					
Revenue Deficiency	$ 178,702					
Current Annualized Revenues	$ 2,155,389	$ 1,009,033	$ 425,982	$ 190,285	$ 470,207	$ 59,882
Proposed System ROR						
Operating Income from COS	$ 352,602	$ 188,695	$ 91,946	$ 27,442	$ 26,672	$ 17,847
Operating Income at System ROR	486,047	230,530	93,317	43,398	97,315	21,489
Incremental Income at System ROR	$ 133,446	$ 41,835	$ 1,371	$ 15,956	$ 70,643	$ 3,642
Revenue Conversion Factor	1.33914	1.33914	1.33914	1.33914	1.33914	1.33914
Incremental Revenue Requirement at System ROR	$ 178,702	$ 56,023	$ 1,836	$ 21,367	$ 94,600	$ 4,877
Percent Increase at System ROR	8.29%	5.55%	0.43%	11.23%	20.12%	8.14%
Step One Increase						
Maximum Increase at 1.15 times System Average Increase	9.53%	9.53%	9.53%	9.53%	9.53%	9.53%
Step One Revenue Increase	$ 62,975	$ -	$ -	$ 18,143	$ 44,832	$ -
Remaining Revenue Deficiency	$ 115,727					
Step Two Increase						
Current Annualized Revenues for Step Two Classes	$ 1,494,897	$ 1,009,033	$ 425,982	$ -	$ -	$ 59,882
Step Two Revenue Increase	$ 115,727	$ 78,114	$ 32,977	$ -	$ -	$ 4,636
Total Proposed Revenue Increase	**$ 178,702**	**$ 78,114**	**$ 32,977**	**$ 18,143**	**$ 44,832**	**$ 4,636**
Class Revenue Increase Allocation						
Current Annualized Revenues	$ 2,155,389	$ 1,009,033	$ 425,982	$ 190,285	$ 470,207	$ 59,882
Proposed Revenue Increase	$ 178,702	$ 78,114	$ 32,977	$ 18,143	$ 44,832	$ 4,636
Proposed Revenues	$ 2,334,091	$ 1,087,147	$ 458,959	$ 208,428	$ 515,039	$ 64,518
Proposed Revenue Increase	**8.29%**	**7.74%**	**7.74%**	**9.53%**	**9.53%**	**7.74%**
Relative Revenue Increase	**1.00**	**0.93**	**0.93**	**1.15**	**1.15**	**0.93**

Summary of Current and Proposed Basic Facility Charges

Description	Company's Present Rate	Company's Proposed Rate	Increase from Present Rate
Residential:			
Good Cents Rates	$ 9.00	$ 11.50	27.8%
Low Use Residential Service	$ 9.00	$ 10.25	13.9%
Residential Service - TOU	$ 13.00	$ 15.50	19.2%
Residential Service - Energy Saver/Conservation Rate	$ 9.00	$ 11.50	27.8%
Time of Use with Demand Charge	$ 13.00	$ 15.50	19.2%
Residential Service	$ 9.00	$ 11.50	27.8%
General Service:			
General Service	$ 19.50	$ 22.00	12.8%
Small Construction Service	$ 9.00	$ 11.50	27.8%
General Service - TOU	$ 23.15	$ 25.65	10.8%
Medium General Service	$ 180.00	$ 190.00	5.6%
General Service - TOU with Demand Charge	$ 195.00	$ 205.00	5.1%
Experimental Program - TOU with Demand Charge	$ 195.00		
Large General Service	$ 1,875.00	$ 1,750.00	-6.7%
Small General Service	$ 23.15	$ 25.65	10.8%
Other Rates:			
Irrigation Service	$ 23.15	$ 25.65	10.8%
Church Service	$ 13.80	$ 16.30	18.1%
Municipal Lighting Service	$ 19.50	$ 22.00	12.8%
Farm Service	$ 9.00	$ 11.50	27.8%
Supplementary and Standby Service	$ 195.00	$ 205.00	5.1%
School Service	$ 13.80	$ 16.30	18.1%
Industrial Power Service	$ 1,875.00	$ 1,750.00	-6.7%

Source: Company's Filing, Exhibit A & Exhibit B.

Survey of Regional Customer Charges

State	Company	Customer Charge ($/month) Residential	Customer Charge ($/month) Small Commercial
SC	**Dominion Energy, South Carolina**	**$ 9.00**	**$ 19.50**
AL	Alabama Power Company	14.50	50.00
NC	Dominion North Carolina Power	10.67	18.93
VA	Dominion Virgina Power	6.58	10.78
FL	Duke Energy, Florida[1]	10.63	14.07
NC	Duke Energy Progress, North Carolina	14.00	21.00
NC	Duke Energy, North Carolina	14.00	19.39
SC	Duke Energy, South Carolina	11.96	11.70
MS	Entergy Mississippi, Inc.	6.75	7.67
FL	Florida Power & Light Company	8.34	10.62
GA	Georgia Power Company	9.97	18.00
FL	Gulf Power Company	19.47	25.25
MS	Mississippi Power Company	26.16	33.46
FL	Tampa Electric Company	15.05	15.05

Notes: (1) The commercial customer charge for Duke Energy Florida represents the secondary commercial charge; (2) All daily customer charges have been pro-rated to represent an average calendar month for comparative purposes.
Source: Utility Tariffs.

Analysis of Residential Bill Impacts

	Customer 1				Customer 2				Customer 3			
	Hypothetical Typical User				One-Third Less Than Typical User				One-Third Greater Than System Average			
Average Usage per Month (kWh)	1000				667				1333			
		Rate		Bill Amount		Rate		Bill Amount		Rate		Bill Amount
Utility Charges - Current Rates												
Monthly Basic Facilities Charge	$	9.00	$	9.00	$	9.00	$	9.00	$	9.00	$	9.00
First 800 kWh	$	0.11602	$	92.82	$	0.11602	$	77.35	$	0.11602	$	92.82
Excess over kWh	$	0.12788	$	25.58	$	0.12788			$	0.12788	$	68.20
Average Monthly Utility Bill Under Existing Rates			**$**	**127.39**			**$**	**86.35**			**$**	**170.02**
Utility Charges - Proposed Rates												
Monthly Basic Facilities Charge	$	11.50	$	11.50	$	11.50	$	11.50	$	11.50	$	11.50
First 800 kWh	$	0.11933	$	95.46	$	0.11933	$	79.55	$	0.11933	$	95.46
Excess over kWh	$	0.13127	$	26.25	$	0.13127			$	0.13127	$	70.01
Average Monthly Utility Bill Under Proposed Rates			**$**	**133.22**			**$**	**91.05**			**$**	**176.97**
Percent Increase from Existing Rates to Proposed Rates				**4.57%**				**5.45%**				**4.09%**

Notes: This exhibit displays bill impacts during the summer.
Source: Company's Filing, Exhibit A & Exhibit B.